ONTARIO POWER AUTHORITY

5

Supply Mix Submissions and Presentations

Volume 5 – December 2005

Ontario Power Authority

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Supply Mix Submissions and Presentations (Web only)

Volume 5 – December 2005

Volume 5 contains the over 185 submissions and 21 presentations that provided input in the development of OPAs supply mix advice to the Minister of Energy. Submissions were received from individuals, companies, groups and organizations and were discussed in Part 2-3 of the Supply Mix Advice Report. Because in some cases, several parties submitted joint submissions, single parties submitted multiple submissions, or others requested that their advice not be posted, the submissions and presentations listed below may not match exactly with the list provided in Part 2-3.

Table of Contents

5.1 Written Submissions to the Supply Mix Project

5.2 Presentations from Expert Interview Sessions

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Supply Mix Submissions and Presentations (Web only)

Volume 5 – December 2005

Detailed Table of Contents

5.1 **5.1 Written Submissions to the Supply Mix Project**

Abram, Aiden (Individual) - Supply Mix Submission - August 11 2005
Aiken & Associates llc - Supply Mix Submission - August 04 2005
Aoki, Wendy (Individual) - Supply Mix Submission - August 04 2005
Arsic, Richard (Individual) - Supply Mix Submission - August 09 2005
Association of Major Power Consumers in Ontario - Supply Mix Submission - August 24 2005
Association of Municipalities of Ontario - Supply Mix Submission - August 25 2005
Atomic Energy of Canada Ltd - Supply Mix Submission - August 26 2005
AWS Public Affairs Consulting - Supply Mix Submission - September 02 2005
Bartley, Glenn BES (Individual) - Supply Mix Submission - Thesis
Bradley, Andrea (Individual) - - Supply Mix Submission - August 05 2005
Brenner, Cathie (Individual) - Supply Mix Submission - August 05 2005
Bruce Power - Supply Mix Submission
California Energy Commission - Supply Mix Submission 01 - July 15 2005
California Energy Commission - Supply Mix Submission 02 - July 15 2005
California Energy Commission - Supply Mix Submission 03 - July 15 2005
Cameco Corporation - Supply Mix Submission - August 26 2005
Campbell, Douglas (Individual) - Supply Mix Submission - August 25 2005
Canadian Bioenergy Association - Supply Mix Submission - August 25 2005
Canadian Chemical Producers Association - Supply Mix Submission - August 04 2005
Canadian District Energy Association - Supply Mix Submission - August 19 2005
Canadian Energy Efficiency Alliance - Supply Mix Submission - August 26 2005
Canadian Manufacturers and Exporters - Supply Mix Submission - August 26 2005
Canadian Mortgage and Housing Corporation - Supply Mix Submission

Canadian Nuclear Association - Supply Mix Submission - July 05 2005
Canadian Nuclear Society Supply Mix Submission - August 24 2005
Canadian Nuclear Workers Council - Supply Mix Submission - August 26 2005
Canadian Solar Industries Association - Supply Mix Submission - August 25 2005
Canadian Wind Energy Association - Supply Mix Submission 01 - August 26 2005
Canadian Wind Energy Association - Supply Mix Submission 02 - Policy Barriers
Christian Farmers Federation of Ontario - Supply Mix Submission - August 26 2005
Citizens for Renewable Energy - Supply Mix Submission - August 01 2005
Clean Affordable Energy Alliance - Supply Mix Submission - August 25 2005
Cogen Canada - Supply Mix Submission
Conference Board of Canada - Supply Mix Submission
Coral Energy Canada - Supply Mix Submission - September 01 2005
Creasy, Colin (Individual) - Supply Mix Submission - August 5 2005
David Suzuki Foundation - Supply Mix Submission 01 - August 25 2005
David Suzuki Foundation - Supply Mix Submission 02 - August 25 2005
Dibben, Roger (Individual) - Supply Mix Submission - August 04 2005
Dunker, Marjut (Individual) - Supply Mix Submission - August 14 2005
Dunning, Lawrence (Individual) - Supply Mix Submission - July 14 2005
Durham Strategic Energy Alliance - Supply Mix Submission - August 29 2005
Dziedzic, Henryk (Individual) - Supply Mix Submission - Thesis - August 26 2005
Edwards, Roy (Individual) - Supply Mix Submission
Edwards, Roy (Individual) - Supply Mix Submission - August 18 2005
Ehrlich, Richard (Individual) - Supply Mix Submission - August 08 2005
Electricity Distributors Association - Supply Mix Submission - October 26 2005
Electricity Market Investment Group - Supply Mix Submission - August 29 2005
Electro Federation Canada - Supply Mix Submission - July 15 2005
EMeter Corporation - Supply Mix Submission - August 26 2005
Enbridge Gas Distribution - Supply Mix Submission - August 26 2005
Encompass Technologies Inc WebGen Systems - Supply Mix Submission - August 26 2005
Energy Council of Canada - Supply Mix Submission - July 2005
Energy Council of Canada - Supply Mix Submission - Letter
Enersource Corporation - Supply Mix Submission - August 22 2005

Eng, Steve (Individual) - Supply Mix Submission - August 05 2005
Epners, Janis (Individual) - Supply Mix Submission - August 10 2005
General Electric Canada - Supply Mix Submission - August 26 2005
Gerson, Helen (Individual) - Supply Mix Submission - Thesis - August 08 2005
Goering, Jack (Individual) - Supply Mix Submission - August 09 2005
Goldstein, Bette-Ann (Individual) - Supply Mix Submission - August 22 2005
Grant, Mark (Individual) - Supply Mix Submission - August 25 2005
Green, D. (Individual) - Supply Mix Submission - August 4 2005
Greening, Dr F.R. - Supply Mix Submission - September 12 2005
Greening, Dr F.R. - Supply Mix Submission - August 28 2005
Greenpeace Canada - Supply Mix Submission 01 - July 13 2005
Greenpeace Canada - Supply Mix Submission 02 - August 26 2005
Greenwood-Speers, Judy (Individual) - Supply Mix Submission - August 06 2005
Hamilton, Aaron (Individual) - Supply Mix Submission - August 04 2005
Harvey, D - Supply Mix Submission
Hastings-James, Margaret (Individual) - Supply Mix Submission - August 04 2005
Heino, Keith (Individual) - Supply Mix Submission - August 11 2005
Helferty, Lloyd (Individual) - Supply Mix Submission - July 09 2005
Henderson, Cate (Individual) - Supply Mix Submission - August 22 2005
Hess, Herbert (Individual) - Supply Mix Submission - November 4 2005
Howard, Sean (Individual) - Supply Mix Submission - August 04 2005
Howes, Terry (Individual) - Supply Mix Submission - August 09 2005
Hughes, Tom (Individual) - Supply Mix Submission - August 25 2005
Hydro One Networks - Supply Mix Submission - August 19 2005
Inco Ltd - Supply Mix Submission - August 26 2005
Independent Electricity System Operator - Supply Mix Submission
Industrial Gas Users Association - Supply Mix Submission - August 26 2005
Intelaport Networks Inc. - Supply Mix Submission
International Innovative Systems - Supply Mix Submission
Jenkins, Rhys (Individual) - Supply Mix Submission - August 25 2005
Jones, Kevin (Individual) - Supply Mix Submission - August 26 2005
Jubenville, Corey (Individual) - Supply Mix Submission - July 13 2005
Junt, J. (Individual) - Supply Mix Submission - August 04 2005
Pejovic, Karney, Colombo - UofT - Supply Mix Submission - August 18 2005
Katz, Miriam (Individual) - Supply Mix Submisison - August 04 2005
Kelman, David (Individual) - Supply Mix Submission - August 04 2005
Ketchum, Anthony (Individual) - Supply Mix Submission - August 04 2005

Krasnodebski, Jan (Individual) - Supply Mix Submission - August 04 2005
Kuhl (Individual_ - Supply Mix Submission - August 25 2005
Laepple (Individual) - Supply Mix Submission - July 10 2005
Lane, Dale (Individual) - Supply Mix Submission - August 25 2005
Lane, Stephanie (Individual) - Supply Mix Submission - August 07 2005
Lavender, L. (Individual) - Supply Mix Submission - August 25 2005
Leong, Vivian (Individual) - Supply Mix Submission - August 04 2005
Levesque, Alain (Individual) - Supply Mix Submission - August 25 2005
Liptrot, B (Individual) - Supply Mix Submission - August 04 2005
Lisman, Alex (Individual) - Supply Mix Submission - August 13 2005
Luxemburger, Leslie (Individual) - Supply Mix Submission - August 09 2005
Maccio, John (Individual) - Supply Mix Submission - August 25 2005
Markvart, Tanya (Individual) - Supply Mix Submission - August 07 2005
Martijn, Erin (Individual) - Supply Mix Submission - August 04 2005
McDonnell, Wendy (Individual) - Supply Mix Submission - August 09 2005
Mckeown, Allan and Dorothy (Individual) - Supply Mix Submission - August 05 2005
Men's Professional Group - Supply Mix Submission 01 - July 29 2005
Men's Professional Group - Supply Mix Submission 02 - July 29 2005
Michie, Leanne (Individual) - Supply Mix Submission - August 05 2005
Miller, Cameron (Individual) - Supply Mix Submission - August 08 2005
Millwright and Machine Erectors Local Union 1007 - Supply Mix Submission
Mogensen, Suzanne (Individual) - Supply Mix Submission - Thesis - August 06 2005
Morningstar, Cory (Individual) - Supply Mix Submission - August 04 2005
Morrison, Kari (Individual) - Supply Mix Submission - August 04 2005
Mountain Equipment Co-op - Supply Mix Submission
NextEnergy Geothermal Solutions - Supply Mix Submission
Niagara Windpower - Supply Mix Submission
Nichols, D. Supply Mix Submission
Nishnawbe First Nations - Supply Mix Submission
Norris, Scott (Individual) - Supply Mix Submission - August 07 2005
Northern WindPower Inc - Supply Mix Submission - July 14 2005
Northwatch - Supply Mix Submission - August 26 2005
On Power Systems Inc - Supply Mix Submission - July 15 2005
Ontario Chamber of Commerce - Supply Mix Submission - August 26 2005
Ontario Clean Air Alliance - Supply Mix Submission 01
Ontario Clean Air Alliance - Supply Mix Submission 02
Ontario Environmental Industry Association - Supply Mix Submission - August 25 2005
Ontario Federation of Agriculture - Supply Mix Submission - August 26

2005
Ontario Mining Association - Supply Mix Submission - August 24 2005
Ontario Power Generation Inc. - Supply Mix Submission - August 26 2005
Ontario Region Indian and Northern Affairs Canada - Supply Mix Submission
Ontario Society of Professional Engineers - Supply Mix Submission - September 14 2005
Ontario Sustainable Energy Association - Supply Mix Submission
Ontario Waterpower Association - Supply Mix Submission 01 - August 26 2005
Ontario Waterpower Association - Supply Mix Submission 02 - August 26 2005
Ontario Waterpower Association - Supply Mix Submission 03
Ontario Waterpower Association - Supply Mix Submission 04
Ontario Waterpower Association - Supply Mix Submission 05
Pembina Institute - Supply Mix Submission
Perkins, Josephine (Individual) - Supply Mix Submission - August 04 2005
Pollution Probe - Supply Mix Submission 01
Pollution Probe - Supply Mix Submission 02
Power Up Renewable Energy Co-operative - Supply Mix Submission - August 26 2005
Power Workers Union - Supply Mix Submission 01
Provincial Council of Women of Ontario - Supply Mix Submission
Przychoczki, Anna Individual Supply Mix Submission Aug 16 2005.pdf
Przychodzki, Sylvia (Individual) - Supply Mix Submission - August 19 2005
Pulleybank, A. (Individual) - Supply Mix Submission - August 04 2005
Rachlis, Josh (Individual) - Supply Mix Submission - August 04 2005
Ransom, Melanie (Individual) - Supply Mix Submission - August 04 2005
Richardson, Carol (Individual) - Supply Mix Submission - August 05 2005
Robbert Associates Ltd. - Supply Mix Submission - August 26 2005
Rowlands I - Supply Mix Submission 01
Rowlands I - Supply Mix Submission 02
Ruddock, Darren (Individual) - Supply Mix Submission - August 26 2005
Sarnia Lambton Chamber of Commerce - Supply Mix Submission
Schaefer, James (Individual) - Supply Mix Submission - August 04 2005
Shannon (Individual) - Supply Mix Submission - August 15 2005
Shore, William (Individual) - Supply Mix Submission - August 15 2005
Shuttleworth, Nan (Individual) - Supply Mix Submission - August 10 2005
Sierra Legal Defence Fund - Supply Mix Submission
Singh, Mark (Individual) - Supply Mix Submission - August 05 2005
Social Housing Services Corporation - Supply Mix Submission - August 26 2005

Society of Energy Professionals - Supply Mix Submission
Bes. Bill Individual Supply Mix Submission Aug 16 2005.pdf
Strong, Bill (Individual) - Supply Mix Submission - August 25 2005
Surruys, Paul (Individual) - Supply Mix Submission - August 26 2005
Sustainable Scale Project - Supply Mix Submission
Taylor, Gord (Individual) - Supply Mix Submission - Thesis - August 04 2005
Taylor, J. (Individual) - Supply Mix Submission - August 25 2005
Thunder Bay Economic Development Department - Supply Mix Submission
Toms, David (Individual) - Supply Mix Submission - August 04 2005
Toronto Board of Trade - Supply Mix Submission - September 30 2005
Toronto Environmental Alliance - Supply Mix Submission
Toronto Medical Officer of Health - Supply Mix Submission
Total Energy Advice Management Ltd. - Supply Mix Submission - July 29 2005
Trebilcock and Hrab - Supply Mix Submission - July 31 2005
Tylak, Stefan (Individual) - Supply Mix Submission - August 05 2005
Union Gas Limited - Supply Mix Submission - August 15 2005
Vivian, Saundi (Individual) - Supply Mix Submission - August 17 2005
Warren, Alan (Individual) - Supply Mix Submission 01 - August 06 2005
Warren, Alan (Individual) - Supply Mix Submission 02 - August 06 2005
Willls, David (Individual) - Supply Mix Submission - July 15 2005
Wilson, Anthony R. (Individual) - Supply Mix Submission - August 05 2005
Wood, L.J. (Individual) - Supply Mix Submission - August 25 2005
Woods, Deborah (Individual) - Supply Mix Submission - August 04 2005
Xuereb, Marc (Individual) - Supply Mix Submission - August 04 2005
Younker R Orangeville Dufferin Wind Coop - Supply Mix Submission - August 24 2005

5.2 Presentations from Expert Interview Sessions

APPrO - Supply Mix Presentation - September 22 2005
BOMA - Supply Mix Presentation - September 21 2005
CanSIA - Supply Mix Presentation - September 22 2005
CANWEA - Supply Mix Presentation - September 22 2005
EDA - Supply Mix Presentation - October 04 2005
Energy Council of Can - Supply Mix Presentation - September 22 2005
Fuel Cells Canada - Supply Mix Presentation - September 22 2005
Hydro One - Supply Mix Presentation - September 21 2005
Ian Rowlands Uof W - Supply Mix Presentation - September 22 2005
IESO - Supply Mix Presentation - October 05 2005

Karney Pejovic UofT - Supply Mix Presentation - September 21 2005
OPG - Supply Mix Presentation - September 26 2005
OWA - Supply Mix Presentation - October 11 2005
Pejovic Karney UofT - Supply Mix Presentation - September 21 2005
Pembina Institute - Supply Mix Presentation - September 20 2005
Pollution Probe - Green Power Targets - October 04 2005
Pollution Probe - Green Power Vision & Strategy - October 04 2005
Pollution Probe - Supply Mix Presentation - October 04 2005
PWU - Supply Mix Presentation - September 20 2005
Social Housing Services Corp - Supply Mix Presentation - October 04 2005
Toronto Environmental Alliance - Supply Mix Presentation - October 04 2005

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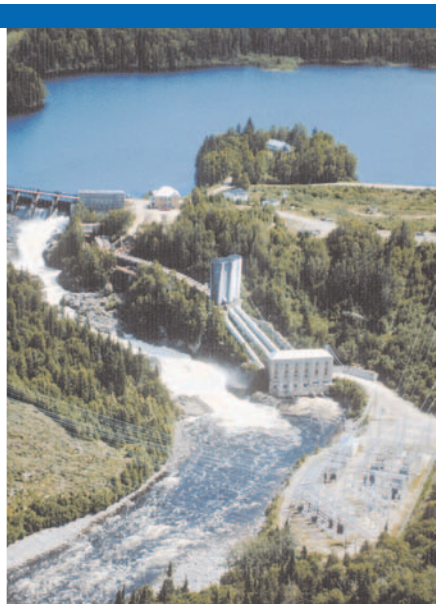

Power for the Future

Towards a Sustainable Electricity System for Ontario

Pembina Institute
for Appropriate Development

Canadian Environmental Law Association

Power for the Future

Towards a Sustainable Electricity System for Ontario

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Any errors and omissions remain the responsibility of the authors.

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About the Pembina Institute

The Pembina Institute is an independent, not-for-profit environmental policy research and education organization specializing in the fields of sustainable energy, community sustainability, climate change and corporate environmental management. Founded in 1985 in Drayton Valley Alberta, the Institute now has offices in Calgary, Edmonton, Vancouver, Ottawa and Toronto.

For more information on the Institute's work, please visit our website at www.pembina.org.

About the Canadian Environmental Law Association

The Canadian Environmental Law Association (CELA) is a public interest law group founded in 1970 for the purpose of using and improving laws to protect the environment and public health and safety. Funded as a legal aid clinic specializing in environmental law, CELA lawyers represent individuals and citizens' groups in the courts and before tribunals on a wide variety of environmental protection and resource management matters. In addition, CELA staff members are involved in a range of initiatives related to law reform, public education and community organization.

Towards a Sustainable Electricity System for Ontario

Executive Summary

May 2004

1. Introduction

The past five years have been a period of extraordinary change and upheaval in Ontario's institutions and policies related to electricity. More changes have occurred in the electricity sector since 1998 than over the preceding nine decades following the creation of the Ontario Hydro-Electric Power Commission (HEPC) in 1906.

The Energy Competition Act of 1998 divided the HEPC's successor, Ontario Hydro, into four separate entities: Ontario Power Generation (OPG), Hydro One, the Ontario Electricity Financial Corporation (OEFC), and the Electrical Safety Authority. In addition, under the legislation, competitive retail and wholesale electricity markets were introduced in May 2002, supervised by the Ontario Energy Board (OEB) and an Independent Market Operator (IMO). However, the government terminated the competitive retail electricity market six months later in the context of high and unstable electricity prices.

In the meantime, from 1997 onwards, a significant portion of the province's nuclear generating facilities were taken out of service for safety and maintenance overhauls. This, in turn, led to an increased reliance on coal-fired generation to meet the province's electricity needs, a situation that has significantly exacerbated the severe air quality problems regularly experienced in southern Ontario.

The new provincial government, elected in October 2003, has made a strong commitment to the phase out of OPG's coal-fired plants by 2007 due to the severe environmental and health impacts of their operation. This state of affairs is further complicated by the consideration that all of the province's existing nuclear generating facilities, which currently account for 28% of the province's generating capacity, will reach the end of their projected operational lifetimes by 2018. The resulting situation was summarized by the province's Electricity Conservation and Supply Task force in its January 2004 report in the following figure:

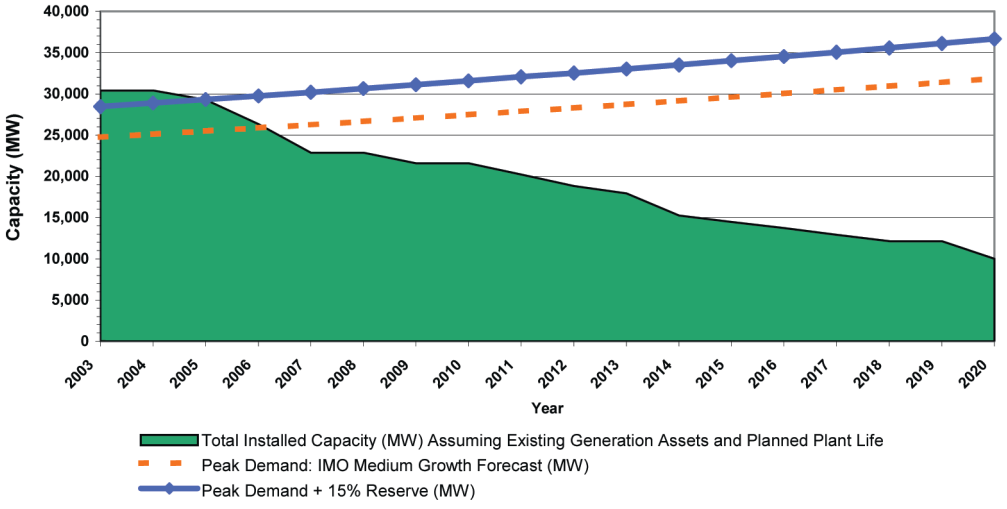


Figure E1: Existing Generation vs. Peak Demand

The combination of the projected end of life of the province's existing coal-fired and nuclear generating stations, and predictions of growing electricity demand have prompted a major debate over the province's future electricity needs, and how those needs might be met. The options that have been proposed to the province range from ambitious energy efficiency programs accompanied by major investments in low-impact renewable energy sources, such as wind and small-scale hydro, to the construction of a series of new nuclear generating facilities.

2. The Pembina Institute/ Canadian Environmental Law Association Sustainable Electricity Project

In this context of change and uncertainty, the Pembina Institute and the Canadian Environmental Law Association undertook a study to answer four key questions regarding Ontario's future electricity path. These questions were as follows:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

3. Assessing the Potential Impact of Energy Efficiency on Future Electricity Demand

In order to answer the first question, regarding the potential impact of energy efficiency programs, a series of generic policy measures was proposed to promote the adoption of energy efficient technologies, cogeneration in the industrial and commercial sectors, and fuel switching from electricity to natural gas, where this is the most efficient option.

The Canadian Integrated Modeling System (CIMS) computer model, developed by the Energy and Materials Research Group at Simon Fraser University, was then used to estimate the reduction in electricity consumption that could be achieved between the present and 2020 through the implementation of these policies; the incremental investment associated with achieving the 2020 energy savings; the resulting changes in natural gas demand from the adoption of energy efficient technologies and practices; and the net cost per kWh saved through energy efficiency measures.

Three types of policy intervention were simulated through the CIMS model:

1. The provision of financial incentives in the form of grants, sales tax removal, or tax credits for the adoption of the most efficient technologies and industrial processes.
2. The provision of innovative financing programs for high-efficiency technologies and industrial processes to facilitate the faster payback of investments in these technologies and processes through energy savings.
3. The removal of barriers to cogeneration in the industrial and commercial sectors, through mechanisms such as net metering and power purchasing agreements.

The CIMS electricity consumption forecast by sector assuming no change in parameters (business as usual) is shown in **Table E1**.

Table E1: CIMS Electricity Consumption Forecast by Sector—Business as Usual, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	36,674	38,430	40,535
Commercial/Institutional		55,279	64,885	76,226	89,489
Industrial	Process	12,709	12,749	12,912	13,049
	Auxiliary	33,440	33,950	36,072	38,269
	Cogeneration	(464)	(497)	(535)	(567)
TOTAL		138,890	147,761	163,105	180,775

The CIMS electricity consumption forecast by sector with all of the three policy changes in place is shown in **Table E2**.

Table E2: CIMS Electricity Consumption Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	30,542	27,277	26,494
Commercial/Institutional		55,279	47,623	40,874	39,201
Industrial	Process	12,709	11,952	10,863	10,058
	Auxiliary	33,440	32,060	33,263	34,570
	Cogeneration	(464)	(1,282)	(2,173)	(3,047)
TOTAL		138,890	120,895	110,104	107,276

The CIMS results show that with the policy assumptions built in to the model for each sector, energy users would significantly change their purchasing habits with respect to energy-using equipment and processes. These changes would reduce business-as-usual electricity consumption by 73,500 GWh/yr (from 180,775 to 107,276 GWh/yr) by 2020. This amounts to a 40% reduction against the business-as-usual forecast.

The electricity savings would result from three types of technological and behavioural changes:

1. The adoption of the most energy efficient technologies instead of conventional products in all sectors
2. The expansion of cogeneration in the industrial and commercial/institutional sectors as energy consumers take advantage of the efficiencies offered by combined heat and power, and generating power through cogeneration and micro-turbines instead of buying from the grid
3. A shift from electricity to natural gas for heating in the residential and commercial/institutional sectors

These changes would be achieved as energy users would take advantage of financial incentives that reduce the capital cost of energy efficient or non-electric technologies, and innovative financing that would allow them to make purchasing decisions more on a life-cycle cost rather than a first-cost basis.

The study finds that capital investments of $18.2 billion by energy consumers over the 2005–2020 period would be required to achieve these savings through energy efficiency, fuel switching, and cogeneration. However, 96% of these costs would be recovered by consumers through their savings in energy consumption resulting from these investments. Ontario's natural gas consumption would increase by 12% over business-as-usual projections by 2020 as a result of the technological and behavioural changes flowing from the measures tested through CIMS.

The study also considers the potential impact of demand response measures that encourage consumers to not use power at peak periods. This is done through pricing mechanisms designed to encourage consumers to delay or manage power-using activities

on an hourly or daily basis at critical peak periods. Estimates developed for the IMO suggest that up to 10% of Ontario's peak demand could be shifted through demand response measures. Consideration is also given to the potential contribution of an on-site solar rooftop program to help address summer peak demand.

The total impact of the modelled energy efficiency measures and potential contribution of demand response programs and on-site solar generation on net grid peak demand are shown in **Table E3**.

As Table E3 shows, net summer peak demand could be reduce by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

Table E3: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	Summer	Winter	Summer	Winter	Summer
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

4. Meeting Remaining Grid Demand

The second and third questions are examined in section 5 of the study. The analysis concludes that it would be reasonable to expect significant contributions to Ontario's electricity supply from low-impact renewable energy sources, such as small-scale hydro, wind, and biomass by 2020 as shown in **Table E4**.

The study finds that, assuming the province maximizes the potential contributions from energy efficiency measures and low-impact renewable energy sources, and phases out the province's coal-fired generating facilities no later than 2010, and given the projected end of life of the province's existing nuclear generating facilities, 4,500 MW of new base load generating capacity will be needed to meet the balance of the province's electricity needs by 2020.

On the basis of costs, environmental and health impacts, speed of construction, and reliability, the study finds that this remaining base load requirement would be best met through combined cycle natural gas generating facilities. However, in light of the concern in the very long term regarding natural gas supplies in North America, these facilities should be seen as an interim measure towards a system that relies on more advanced renewable energy sources in the future.

Table E4: Potential Renewable Energy Supply, 2010–2020

	2010			2015			2020		
Source	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
Wind	7,884	1,317	3,000	12,208	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4205	281	600	5,606	375	800
TOTAL	15,768	2,151	4,500	22,983	3,377	7,100	32,762	4,649	9,800

The final estimated grid demand and supply mix is outlined in **Table E5**.

Table E5: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

The study compares the financial, economic, and social implications of the supply options available to the province to meet its future electricity needs. Under the business-as-usual scenario, assuming that existing hydro and peaking gas and oil-fired (assumed to be replaced by gas) generating capacity are retained, demand response programs are pursued, and that renewable energy sources are maximized, but if aggressive efficiency programs and new combined cycle natural gas baseload supply are not pursued, a peak supply gap of nearly 15,000MW would emerge by 2020. Meeting this gap through new nuclear generation would carry a capital cost of over $39 billion.

The capital costs of addressing the same gap through a combination of energy efficiency measures, fuel switching, cogeneration, and new combined cycle natural gas generation as outlined in this study, by comparison, would be in the range of $23 billion. In addition to avoiding certain capital costs, a supply strategy focused on improving energy efficiency rather than creating new generation would carry with it other benefits: the avoided costs of producing the electricity and gas saved as a result of energy efficiency measures, and the environmental, health, safety, and security co-benefits associated with avoiding the need to construct and operate new generating capacity that would be required under business-as-usual scenarios. There would also be overall improvements in housing quality and the competitiveness of Ontario industry as a result of investments in more modern and energy efficient technologies.

5. Implementing a Sustainable Electricity System in Ontario

Achieving the potential reduction in electricity demand identified in this study by 2020 will not be easy or without risk. However, the study notes that other jurisdictions in North America are implementing the types of program that will be needed in Ontario to achieve this target. California, for example, has reduced peak power demand by 20%, or 10,000 MW over the past 20 years, with a combination of utility demand side management (DSM) programs, and building and appliance standards.

The study concludes that with an appropriate regulatory foundation in the form of minimum energy efficiency standards and labelling, Ontario Energy Board (OEB) incentive mechanisms for utilities, and improved grid access for cogenerators, major reductions in electricity consumption can be achieved without excessive costs to government or energy consumers, or by penalizing low-income members of Ontario society.

The specific measures recommended to the province in the study are as follows:

1. The Government of Ontario should adopt minimum energy efficiency standards under the Energy Efficiency Act equivalent to the energy efficiency levels required for Energy Star labelling for all major electricity-using devices and equipment when the market share for new or replacement energy efficient models surpasses 50%, and not later than 2010 for all devices. The province should develop its own energy efficiency standards for equipment not covered by Energy Star.

2. The provincial Building Code should be amended to require R2000, Canadian Building Improvement Program (CBIP), or equivalent energy efficiency performance for all new buildings and building renovations by 2010.

3. The Planning Act should be amended to permit municipalities to make energy efficiency design requirements a condition of planning and site approvals for new developments.

4. The most energy efficient technologies in all sectors and end-uses should be labelled through the Energy Star program or, if not included in Energy Star, through a provincial labelling system.

5. The OEB performance-based rate setting and DSM incentive mechanism model currently applied to Enbridge Gas Distribution should be extended to Hydro One and all of Ontario's electrical distribution utilities. All distribution utilities should be required to set targets for energy efficiency gains and be allowed to then share in the benefits of DSM programs. The incentive mechanisms should allow utilities without DSM capabilities to meet their targets by contracting the delivery of DSM programs to other electrical and gas utilities, the energy service industry, or specialized non-profit agencies.

6. The Government of Ontario should expand its current net metering policy to include all industrial, commercial/institutional, and residential users, and develop grid inter-tie specifications and training programs for utility staff. A series of annual special RFPs or feed-in tariffs should be issued to encourage smaller industries and large commercial and institutional facilities to develop their cogeneration potential.

7. The Government of Ontario should establish a partnership with utilities, financial institutions, energy service companies, municipalities, and other stakeholders to offer a series of financing mechanisms to assist electricity consumers in all sectors to finance the adoption of energy efficient products and technologies and measures out of the savings they will achieve through these investments.

8. The Government of Ontario should enter into an agreement with the federal government under the auspices of the federal government's Kyoto Protocol implementation plan to share the costs of providing the following financial incentives for the adoption of energy efficient technologies:
   - Grants for high efficiency home energy retrofits and new R2000 homes
   - Grants towards the additional cost of new high-efficiency commercial buildings, and commercial building retrofits
   - Sales tax rebates for all Energy Star products in all sectors and small-scale renewable energy power sources
   - Business tax credits for industrial energy efficiency equipment and cogeneration systems.

These incentives should focus initially on technologies where the largest reductions can be achieved at the lowest cost, such as commercial HVAC and lighting, and industrial drive power. The incentives should be in effect only until the market share of the efficient technology reaches 50%.

9. Mechanisms to ensure the delivery of programs to low-income consumers should be incorporated into the DSM mandates and incentives provided to energy and electrical distribution utilities. A specific portion of DSM spending should be set aside for this purpose, including revenues from the Public Benefits Charge proposed in Recommendation 11.

10. The Government of Ontario should adopt legislation creating a new agency, the Ontario Sustainable Energy Authority, reporting to the Minister of Energy, to lead and coordinate the province's energy efficiency efforts. The agency's functions should include:

- The coordination and oversight of the development and implementation of provincial energy efficiency standards and labelling programs
- Ensuring the consideration of energy efficiency in the policies and programs of provincial government agencies
- The ongoing assessment of the effectiveness of energy efficiency programs being delivered by utilities and provincial agencies, including low-income programs and the provision of recommendations for their improvement to the provincial government and the OEB
- The forecasting of province's future electricity needs
- Research, development, and education and information dissemination on energy efficient technologies and practices.

The proposed Ontario Power Authority, responsible for issuing requests for proposals for the construction of new generating capacity, should be a division of the new agency.

11. A PBC of 0.3 cents/kWh should be applied on all electricity sales to finance energy efficiency and low-income assistance programs.

12. The Government of Ontario should implement the following demand response policies:

- The OEB should be directed to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market.
- The Government of Ontario should assess the infrastructure needed to encourage and facilitate demand response in the Ontario market. A portion of the revenues generated by the PBC proposed in Recommendation 11 should be used to meet the costs of providing the required infrastructure.
- All electricity consumers should be able to participate in demand response programs, and should not be capped in terms of the level of their participation.

13. The Government of Ontario should undertake a design and costing study for a 200,000 unit solar PV roof program modelled on those undertaken in Europe and the United States, and implement this program using a feed-in tariff funding mechanism.

14. The Government of Ontario should issue, through the IMO or proposed Ontario Electricity Authority, RFPs for supply from wind, upgraded existing or new small scale hydro, solar, the use of waste-generated methane from municipal, agricultural, industrial sources and other low-impact renewable energy sources. The initial RFPs should seek to have 4,500 MW capacity in place by 2010, followed by additional calls for supply up to 7,100 MW by 2015 and 9,800 MW by 2020.

15. The Government of Ontario should undertake, on an urgent basis, a complete up-to-date assessment of the potential contributions from onshore and offshore wind generation, small scale hydro, and the use of waste digestion-generated methane, to the province's future energy supply. This effort should include primary research as required, including detailed wind potential mapping.

16. The Government of Ontario should initiate a research and development program on renewable energy technologies funded through the PBC proposed in Recommendation 11. This should

include both technology development and the resolution of grid integration issues.

17. The IMO should adopt management practices designed to forecast power outputs from wind power capacity and run-of-river hydro (and solar PV systems), and be prepared to dispatch hydro storage and existing natural gas facilities as needed to provide base load capacity.

18. The Government of Ontario should establish and expedite the completion of a consultative process to develop land-use guidelines for the siting of renewable energy generating facilities.

19. The Government of Ontario should develop guidelines, in conjunction with the federal government, for the approval of offshore wind power generation facilities.

20. The Government of Ontario should issue, through the IMO or the proposed Ontario Electricity Authority, a request for proposals for long-term base load supply, meeting the construction time, cost, reliability, and environmental, health, and safety performance of combined cycle natural gas generating facilities. The call for proposals should seek to have 4,200 MW of new base load supply in place by 2007 and 4,500 MW in place by 2020.

The study concludes that Ontario is now at a critical juncture in terms of its future energy path, and that the decisions made about electricity policy over the next year will set the province's course for the next 20 or 30 years. The choices the province makes will have major implications for the health, environment, safety, and security of Ontario residents, and the competitiveness of Ontario's businesses and industries for decades to come.

The study shows that the choice faced by the province is clear. The province can take the path of making a massive investment in a generation technology, namely nuclear power, that has never lived up to its promise and is in large measure responsible for the environmental, reliability, and financial crises now facing Ontario's electricity system, and which carries with it enormous environmental and economic risks and costs to present and future generations of Ontarians.

In the alternative, the province can choose the path, as laid out in the study, of setting a policy framework that will result in the widespread adoption of proven energy efficient technologies and practices that will reduce consumers' energy bills, improve air quality, protect the health and safety of Ontario residents, and result in a more, safe, secure, and reliable electricity system.

The study consists of a main report and four appendixes:

- A report by Mark Jaccard and Associates on the CIMS modelling
- A report on the history and estimated timelines and refurbishment costs of Ontario's nuclear generating facilities
- A review of recent energy efficiency initiatives in North America, prepared by the Pembina Institute
- A review of combustion technologies for electricity generation, prepared by the Pembina Institute

All of the project materials are available on the websites of the Pembina Institute for Appropriate Development (**www.pembina.org**) and the Canadian Environmental Law Association (**www.cela.ca**).

Power for the Future

Towards a Sustainable Electricity System for Ontario

May, 2004

1. Ontario's Emerging Electricity Challenge 1
1.1. The Energy Competition Act, 1998 1
1.2. The Electricity Market Opens (and Closes) 1
1.3. The NAOP and Coal-Fired Generation 2
1.4. Projections of Rising Demand and Falling Supply 2
1.5. The Debate over Energy Efficiency and the Future Shape of Ontario's Electricity System . . . 5
1.6. Project Overview 7
2. Project Goals and Methodology 8
2.1. Guiding Principles for a Sustainable Electricity System 8
2.2. Methodology 8
3. Reducing Electricity Consumption 10
3.1. Approaches to Reducing Electricity Demand 11
3.1.1. The Adoption of Energy Efficient Technologies 11
3.1.2. Cogeneration 11
3.1.3. Eliminating the Use of Electricity for Heating 12
3.2. Policy Options to Reduce Grid Consumption 12
3.2.1. Minimum Efficiency Codes, Standards, and Labelling of Energy Efficient Technologies . . 12
3.2.2. Financial Incentives for the Most Energy Efficient Technologies and Industrial Processes . 12
3.2.3. Innovative Financing Programs for High Efficiency Technologies and Practices 12
3.2.4. Net Metering and Power Purchasing Agreements for Cogeneration 13
3.3. Using the CIMS Model to Evaluate Demand Side Policy Options 13
3.3.1. The CIMS Model 13
3.3.2. How the CIMS Model Was Used to Simulate Energy Efficiency Policies 14
3.4. The CIMS Results 15
3.4.1. The Impact of Modelled Policies on Electricity Consumption 15
3.4.2. The Impact of Energy Efficiency, Increased Cogeneration, and Fuel Switching on Natural Gas Consumption 17
3.4.3. The Costs of Energy Efficiency Improvements 17
3.4.4. Stock Turnover and Minimum Energy Efficiency Standards 18
3.4.5. The Most Cost-Effective Ways to Reduce Electricity Use 19
3.5. Estimating Peak Demand Reduction from Efficiency Improvements, Increased Cogeneration, and Fuel Switching 22
4. Demand Response and Peak Load Shaving 23
4.1. Demand Response Measures 23
4.2. Load Shaving through On-site Generation 23

4.3. Estimating Remaining Grid Peak Demand 24
5. Meeting Residual Grid Demand 25
5.1. Remaining Grid Demand 25
5.2. Renewable Supply Options 25
5.2.1. The Ability of Renewable Energy Sources to Meet Peak Demand 26
5.2.2. Hydroelectric Power Generation 27
5.2.3. Large-Scale Wind Power Generation 27
5.2.4. Landfill, Sewage, and Anaerobic Waste Digestion Gas Capture and Generation (Biomass) 28
5.3. Summary of Renewable Energy Potential and Remaining Demand 28
5.4. Supply Options to Meet Remaining Grid Demand 29
5.4.1. Imports of Electricity from Other Jurisdictions 29
5.4.2. New or Refurbished Nuclear Generating Facilities 30
5.4.3. "Clean" Coal 31
5.4.4. Combined Cycle Natural Gas-Fired Generation (CCNG) 31
5.5. Supply Options Summary and Conclusions 33
6. Conclusions and Recommendations 36
6.1. Energy Efficiency Potential and Remaining Grid Demand 36
6.2. Meeting Remaining Grid Demand 37
6.3. Implementing a Sustainable Electricity System 39
6.3.1. Maximizing the Efficient Use of Electricity 39
6.3.1.1. Foundation Policies 39
6.3.1.2. Provincial Energy Efficiency Programs 40
6.3.1.3. Provincial Leadership and Coordination of Energy Efficiency Programs 42
6.3.1.4. Costs and Cost Sharing 42
6.3.1.5. Demand Response Measures 44
6.3.2. Achieving a Sustainable Supply Mix 44
6.3.2.1. Renewable Portfolio Standard/Requests for Proposals 44
6.3.2.2. Renewable Energy Potential Assessment 45
6.3.2.3. System Integration Improvements for Renewable Energy 45
6.2.3.4. Resolution of Land-Use Planning and Site Approval Issues for Low-Impact Renewable Energy Sources 45
6.3.2.5. Long-term Supply Contracts for Required Base Load 45
6.4. Implementation Plan 46
6.5. Conclusions 46
Appendix 1: M. K. Jaccard and Associates, "Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario" *55*
Appendix 2: D. Martin, "Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs" 101
Appendix 3: The Pembina Institute, "Energy Efficiency Program Case Studies" 135
Appendix 4: The Pembina Institute, "A Comparison of Combustion Technologies for Electricity Generation" 159

1. Ontario's Emerging Electricity Challenge

The past five years have been a period of extraordinary change and upheaval in Ontario's institutions and policies related to electricity. More changes have occurred in the electricity sector since 1998 than over the preceding nine decades following the creation of the Ontario Hydro-Electric Power Commission (HEPC) in 1906.[1]

1.1. The *Energy Competition Act*, 1998

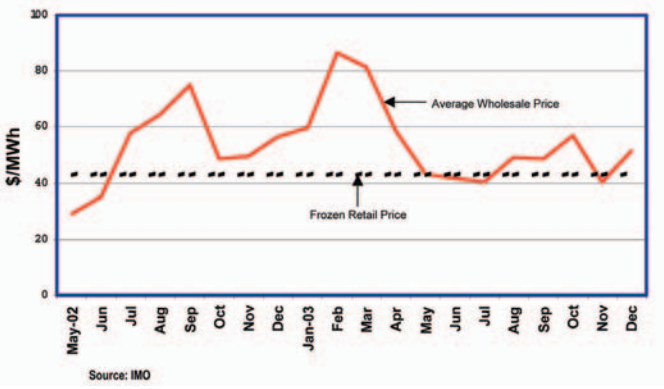
Under the *Energy Competition Act*, adopted in 1998, the HEPC's successor, Ontario Hydro, established as a Crown corporation in 1973,[2] was broken up into a number of entities. These included three separate companies owned by the province: Ontario Power Generation (OPG), which assumed Ontario Hydro's existing generating assets; Hydro One, responsible for transmission and distribution infrastructure; and the Ontario Electricity Financial Corporation (OEFC), which assumed $22 billion of Ontario Hydro's accumulated debt.[3] A fourth entity, the Electrical Safety Authority (ESA), was created to assume the utility's electrical safety inspection functions. [4]

The second key theme of the legislation was the introduction of competitive retail and wholesale electricity markets in Ontario, conferring new powers on the Ontario Energy Board (OEB) to regulate the market and creating an Independent Market Operator (IMO) to operate the technical aspects of the new markets. In the past the province had relied on Ontario Hydro, subject to some limited oversight by the OEB and the Ministry of Energy, to plan for and establish electricity-generating capacity to meet the province's electricity needs. This approach was to be replaced by competitive markets, which would rely on the private sector to plan for and develop electricity supply in response to the province's needs, under a regulatory regime administered by an expanded OEB.[5] To ensure a competitive market, OPG was required to reduce its share of the province's electricity supply from over 85% to 35% by 2010.[6]

1.2. The Electricity Market Opens (and Closes)

Following a series of delays, competitive markets were opened in May 2002. However, this was followed by a period of rising electricity prices, as shown in **Figure 1.1** below. [7]

Figure 1.1:
Ontario Wholesale Electricity Spot Prices (May 2002–December 2003)[8]



In response to public concerns over the sudden increases in electricity prices, the government terminated the competitive retail electricity market in November 2002. At that time, the provincial government adopted a fixed electricity price of 4.3 cents per kWh, retroactive to May 1, 2002, and stated that this price would stay in place for the following six years. Rebates of $75 to electricity consumers for the cost of electricity while the competitive market was in place were also announced, at a total cost of $335 million. The cost of the difference between the fixed retail electricity price and wholesale electricity price was to be covered via OPG revenues from electricity sales. In practice, as of February 2004, revenues had fallen $852 million short of wholesale electricity costs,[9] with the difference being added to the debt administered by the OEFC.[10]

The announcement of the termination of the competitive retail market was accompanied by some modest initiatives related to renewable energy and efficiency. These included: [11]

- A commitment that the government reduce its electricity consumption by 10% and source 20% of its own energy needs from renewable sources;
- The provision of tax incentives for the purchase of energy efficiency equipment by industry and sales tax rebates for consumers for the purchase of high-efficiency appliances; and
- A 10-year corporate income tax holiday for new suppliers of electricity from clean, alternative, or renewable sources.

In addition, in July 2003, the government announced that it would introduce a requirement that the amount of electricity provided in Ontario from renewable sources (defined as hydro, wind, and biomass) would, starting in 2006, increase by 1% per year over eight years, to total 3,000 MW by 2014.[12] No legislation or regulations to actually implement the renewable energy standard were announced or implemented prior to the 2003 provincial election.

1.3. The NAOP and Coal-Fired Generation

In the meantime, in July 1997 an external review raised major concerns regarding the maintenance and safety of Ontario's nuclear generating assets.[13] In response, Ontario Hydro adopted a Nuclear Asset Optimization Plan (NAOP). Under the plan, seven generating units[14] were taken out of service for repair and overhaul. Investments of between $5 billion and $8 billion over four years in the refurbishment of Ontario Hydro's nuclear generating facilities were announced.[15]

As part of the NAOP, Ontario Hydro announced its intention to rely on its coal-fired generating facilities (Lakeview [Mississauga]; Nanticoke; Lambton; Thunder Bay; and Atikokan) to replace the power supplies lost as a result of the taking out of service of the seven nuclear generating units. This lead to major increases in emissions of smog and acid rain precursors, heavy metals, and greenhouse gases from these facilities. Between 1995 and 2001, their greenhouse gas emissions increased by a factor of 2.3, and emissions of the smog and acid rain precursors sulphur dioxide (SO_2) and nitrogen oxide (NOx) had doubled and increased by a factor of 1.7, respectively.[16]

As a result, in 2001 OPG's coal-fired plants accounted for the following:[17]

- 27% of Ontario's SO_2 emissions
- 20% of Ontario's greenhouse gas emissions
- 14% of Ontario's NOx emissions
- 67% of Ontario's chromium emissions
- 34% of Ontario's airborne mercury emissions

The increased emissions from the Lambton, Nanticoke, and Lakeview facilities in particular have significantly exacerbated the severe air quality problems regularly experienced in southern Ontario[18] and emerged as a major political issue in the province. In light of the health and environmental impacts of their operation, all three major political parties committed to a phase out of the coal-fired plants during the October 2003 election campaign.

OPG encountered significant challenges in the implementation of the NAOP, with the first of the four laid-up Pickering "A" units only coming back into service in September 2003. The cost of this return to service was $1.25 billion. The original budget for the return to service of all four units had been $780 million, with the first unit expected to return to service in June 2000.[19] Two of the Bruce units were brought back in service in October 2003 and January 2004, respectively.[20] Both were significantly over budget and behind schedule as well.[21]

1.4. Projections of Rising Demand and Falling Supply

The overall situation flowing from this extended period of policy instability is one of growing concern regarding the security and reliability of the province's electricity supply. Delays in return to service of nuclear generating facilities have resulted in significant growth in reliance on imports of power during periods of high demand.[22] At the same time, most of the new generation facilities that were being considered by non-OPG proponents in anticipation of a competitive electricity market have been placed on hold[23] due to the unstable policy environment, the fixed electricity price adopted in November 2002, and the continued provincial financing of the refurbishment of OPG's nuclear generating facilities.

In the meantime, Ontario Hydro and its successor OPG had not developed any major new generating capacity since the completion of the Darlington plant in 1993. The reasons for this included a focus on energy efficiency and demand side management in the early 1990s, and, after 1995, anticipation of the establishment of a competitive market and need to reduce OPG's market share. Ontario Hydro also began to wind down its efficiency and demand side management programs from 1993 onwards as part of the

restructuring undertaken by then Chairman Maurice Strong[24] and as a consequence of an oversupply situation following the commissioning of the Darlington facility. The remaining energy efficiency programs initiated by the Ministry of Environment and Energy and other provincial agencies in the early 1990s were abandoned following the 1995 election.[25]

The new provincial government, elected in October 2003, has made a strong commitment to the phase out of OPG's coal-fired plants by 2007 due to the severe environmental and health impacts of their operation.[26] As shown in **Table 1.1**, these plants currently account for 23% of Ontario's electricity supply. In addition, in November 2003 the government announced the abandonment of the fixed electricity price of 4.3 cents per kWh as of April 1, 2004, going to 4.7 cents per kWh for the first 750 kWh consumed and 5.5 cents per kWh for consumption beyond that level. This step reflected the government's view that the fixed price approach was not financially sustainable.[27]

Table 1.1: Ontario Electricity Supply, 2003[28]

Source	GWh	%	Peak (MW)	%	Capacity (MW)
Coal	35,098	23	5,865	23	7,285
Nuclear	61,040	40	7,140	28	10,720
Hydro	33,572	22	6,375	25	7,665
Peaking Gas and Oil	12,208	8	3,060	12	4,645
Imports	10,682	7	3,060	12	
Total Demand	152,600		25,500		30,315

This state of affairs is further complicated by the consideration that all of the province's existing nuclear generating facilities,[29] which currently account for 28% of the province's generating capacity, will reach the end of their projected operational lifetimes by 2018. This is shown in **Tables 1.2** and **1.3**.[30]

Table 1.2: Ontario Power Generation CANDU Reactors: "A" Plant Phase-Out Schedule[31]

Station Capacity	Unit	Comm'l Oper'n[32]	First Shutdown	Second Shutdown	Life
Pickering "A" 4 x 515 MWe (net)	1	07/1971	12/1983–09/1987	12/1997–SD[33]	?
	2	12/1971	08/1983–11/1988	12/1997–SD	?
	3	06/1972	06/1989–08/1991	12/1997–SD	?
	4	06/1973	08/1991–03/1993	12/1997–09/2003	13 yrs–2016
Bruce "A" 4 x 769 MWe (net)	1	09/1977	01/1998–SD		?
	2	09/1977	10/1995–SD		?
	3	01/1978	01/1998–02/2004		8 yrs–2012
	4	01/1979	01/1998–10/2003		13 yrs–2016

Table 1.3: Ontario Power Generation CANDU Reactors: "B" Plant Phase-Out Schedule[34]

Station Capacity	Unit	Commercial Operation	25 years
Pickering "B" 4 x 516 MWe (net)	5	05/1983	2008
	6	02/1984	2009
	7	01/1985	2010
	8	01/1986	2011
Bruce "B" 4 x 860 MWe (net)	5	03/1985	2010
	6	09/1984	2009
	7	04/1986	2011
	8	05/1987	2012
Darlington 4 x 881 MWe (net)	1	11/1992	2017
	2	10/1990	2015
	3	02/1993	2018
	4	06/1993	2018

As a result, there is growing concern among the public, energy consumers, and the government over both the province's short-term ability to meet peak electricity demand,[35] and its longer-term electricity supply.[36] Public concerns about the security of the province's future electricity supply were further reinforced by the August 2003 blackout.

The overall situation with respect to the province's electricity supply and demand over the next 15 years, assuming no significant efforts to reduce electricity demand, the phase out of the coal-fired plants, and the run-down of existing nuclear generating facilities, was summarized by the province's Electricity Conservation and Supply Task Force in its January 2004 report as shown in **Figure 1.2**[37].

In developing its estimate, the Electricity Conservation and Supply Task Force extrapolated the IMO's 2003–2013 forecast of electricity consumption and peak demand from 2005 to 2020 as shown in **Table 1.4**.[39]

The implication of these trends is that Ontario will need to make major decisions about long-term electricity policy in the relatively near future. These include questions on the shape of future demand and

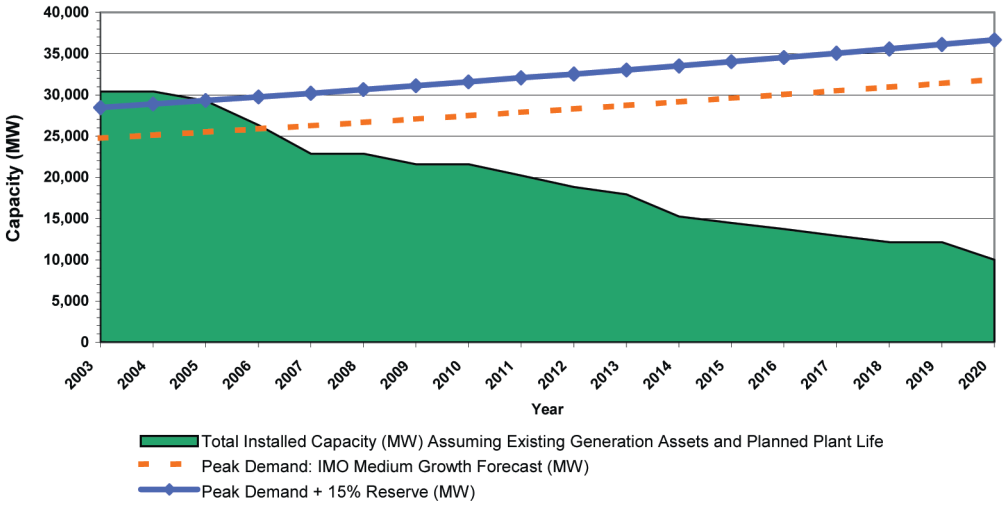


Figure 1.2: Existing Generation vs. Peak Demand[38]

Table 1.4: Forecast Electricity Consumption and Peak Demand, 2005–2020

	2005	2010	2015	2020
Consumption (GWh/yr)	153,000	164,000	172,000	180,000
Peak Demand[40] (MW)	25,500	27,800	28,700	32,000

supply. The business-as-usual projections from the Task Force and the IMO, for example, do not consider the potential reduction in future demand that programs and policies adopted by the provincial government to promote energy efficiency might provide.

Even if energy efficiency programs were to be successfully adopted, consideration also needs to be given to how the remaining demand for electricity might be met. The options range from investing in the refurbishment of the existing nuclear generating facilities to extend their projected lifetimes, or even in the development of new nuclear generating facilities, to meeting the province's needs though low-impact renewable energy sources, such as wind and small-scale hydro.

In the case of both energy efficiency programs and new supply options, decisions on the path forward will need to be made in the relatively near future, as most available options are associated with potentially long lead times to full implementation. Equipment such as industrial motors and residential appliances have lives of 10 to 15 years. It could therefore take that long to replace all of the existing equipment with more efficient units. Buildings are renovated infrequently, and there may be similar delays in the adoption of more energy efficient technologies and practices.

1.5. The Debate over Energy Efficiency and the Future Shape of Ontario's Electricity System

A number of recent reports have examined the questions of the future shape of Ontario's electricity system in considerable detail. Among the most prominent of these have been the work of the province's Electricity Conservation and Supply Task Force, completed in January 2004[41] and a July 2003 report completed by Torrie Smith Associates for the Campaign for Nuclear Phase-Out.[42]

Both studies are in overall agreement on the direction of rising future electricity demand in the absence of efforts to improve energy efficiency and reduce demand. They are also in agreement on the wind down of the province's existing nuclear and coal plants for technological as well as policy reasons. However, the studies disagree strongly on the potential contributions from energy efficiency measures to meeting the province's future energy needs, and, by implication, the levels and types of new supply that will be needed to meet future electricity demand.

The Electricity Supply and Conservation Task Force, for its part, only projected a modest reduction in electricity demand of approximately 5,000 MW,

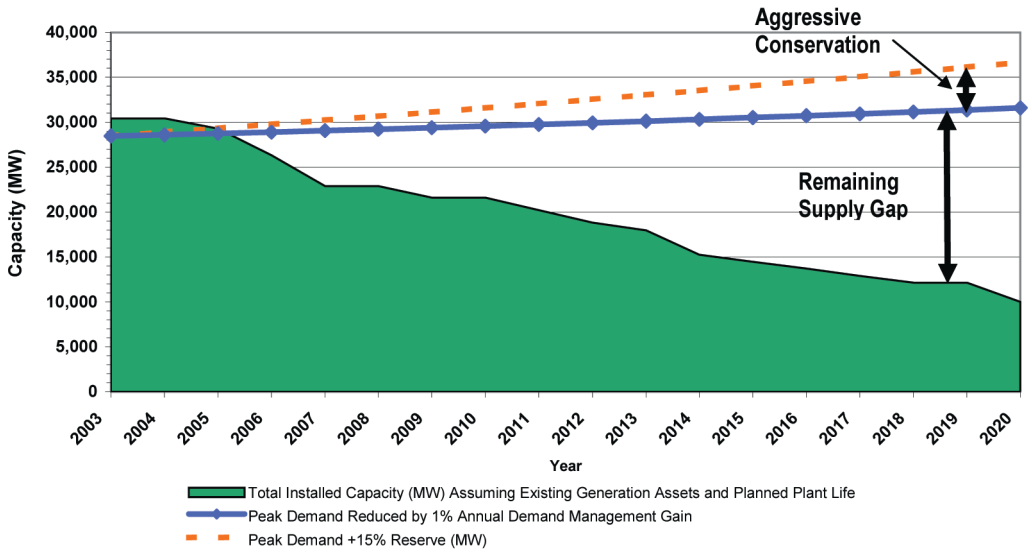


Figure 1.3: Future Demand/Supply Balance[43]

consisting of the government target of 5% plus an additional 700 MW of peak demand reduction through "demand response" measures such as innovative pricing and smart metering. The Task Force called this reduction "aggressive conservation," although the peak demand by 2020 was still projected to be higher than in 2003, as is shown in the Task Force's **Figure 1.3**.

As shown in **Figure 1.4**, this continued growth in demand, in combination with the expected closure of coal-fired generating facilities and the run down of existing nuclear generating facilities by 2018, resulted in a projection by the Task Force for the need for 12,700 MW of new generating capacity, over and above what can be achieved through the "aggressive" pursuit of renewable options, such as wind, hydro, and biomass.[44] The Task Force's report implied that this need would have to be met through new natural gas-fired generation or new and refurbished nuclear generation capacity.

The March 2004 report of the Ontario Power Generation Review Committee[46] reached similar conclusions, stating that "renewable energy sources, conservation and co-generation are all important, but cannot fully bridge the supply gap."[47] The committee did not give estimates of how much these sources might be able to contribute, but projected a potential supply shortage of between 5,000 and 7,000 MW by 2007.[48]

The July 2003 Torrie Smith Associates[49] study reached very different conclusions. As shown in **Figure 1.5**, it found that grid power consumption could be reduced significantly against current levels of demand by 2020 through the following:

- The replacement of all electricity-using equipment with the most energy efficient commercially available equipment today
- The maximization of industrial and commercial sector cogeneration and other on-site power sources
- The elimination of the use of electricity for space and water heating

The remaining electricity demand could be filled through a combination of existing hydro facilities and new wind, biomass, small-scale hydro, and solar, eliminating the need for nuclear or fossil fuel-fired generation. However, 3,000 MW of imported power from Quebec and Manitoba would be required to meet peak demand.

The conclusions of these studies present the provincial government with a number of dilemmas in terms of its future electricity policies. The wide variations in their findings regarding the potential contributions from energy efficiency, for example, leave the province with questions about the appropriate level of effort to put into energy efficiency programs, the scale of the province's future supply needs, and the best supply options to meet those needs.

Figure 1.4:
Electricity Supply and Conservation Task Force Projection of Generation vs. Peak Demand—With Renewables[45]

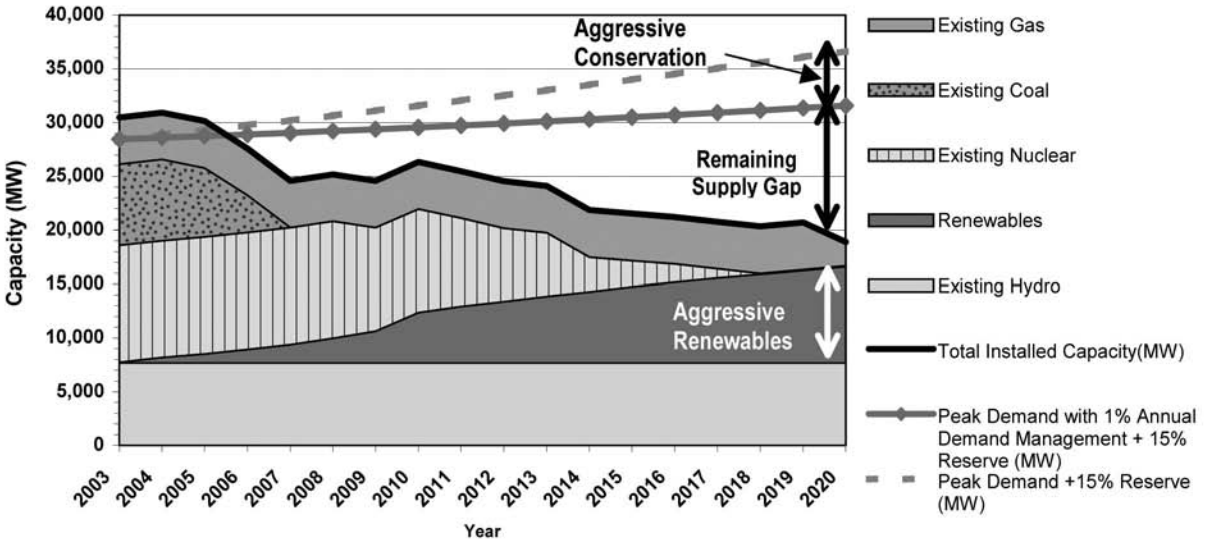
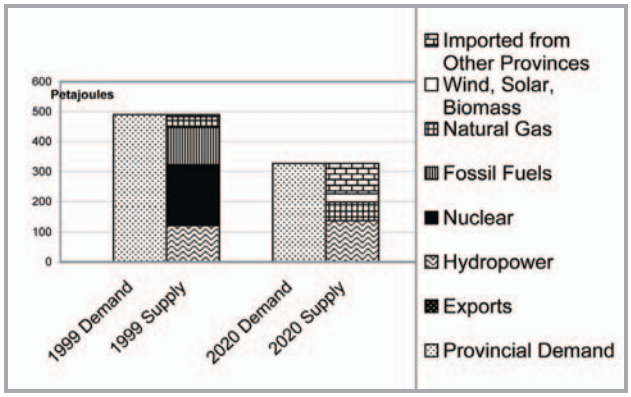


Figure 1.5:
Torrie Smith Associates Projection of Electricity in Ontario 1999 and 2020—Nuclear/Coal Phase-Out[50]



1.6. Project Overview

In light of this period of extraordinary change and upheaval in Ontario's electricity institutions and policies, and the debate over the future shape of Ontario's electricity needs and supply, this study seeks to build on the work of both the Electricity Supply and Conservation Task Force and Torrie Smith Associates, and to answer four key questions regarding the province's future electricity path. These questions are as follows:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

The overall structure of this study is as follows:

Section 1 provides the overall context and rationale for the study.

Section 2 outlines the definition of an environmentally and economically sustainable electricity system that provides the normative framework for the study. This section also describes the study's methodological approach.

Section 3 describes the energy efficiency policies tested using computer modelling and the outcomes of the modelling in terms of impact on electricity demand, natural gas consumption, and societal and program costs.

Section 4 develops an estimate of remaining grid demand, once energy efficiency policies have been implemented, also considering the potential impact of demand response and other peak reduction measures.

Section 5 examines electricity supply options for meeting the remaining grid demand, including low-impact renewable energy sources, and refurbished or new nuclear and fossil-fuel sources.

Section 6 summarizes the study's overall findings with respect to the four research questions. It also provides policy recommendations for the province to maximize the contributions from efficiency, fuel switching, and cogeneration in the most efficient way possible, and to ensure an environmentally and economically sustainable supply to meet the province's remaining electricity demand.

2. Project Goals and Methodology

2.1. Guiding Principles for a Sustainable Electricity System

A sustainable energy path for Ontario's electricity supply and demand is defined, for the purposes of this study, as one that minimizes the impact of electricity supply and demand on the environment and human health, uses only environmentally and economically sustainable sources of energy, and provides the reliable energy services that Ontario's citizens and businesses need at a reasonable cost.

The specific features of a sustainable energy path for Ontario's electricity supply and demand would include the following:

- Using electricity as efficiently as possible and with as even a load curve as possible
- Using electricity only for services for which there is no sustainable alternative
- Producing power at the consumer's site, wherever possible, to make best use of efficiencies such as combined heat and power, and local renewable energy sources
- Using a wide variety of grid power sources in a distributed fashion to maintain the reliability and resilience in the grid
- Using only renewable energy sources to generate electricity
- Phasing out energy sources that are not environmentally or economically sustainable, such as fossil fuels and nuclear energy
- Using lower impact non-renewable fuels such as natural gas as bridging fuels to a situation where the electricity system can rely on renewable energy sources to meet demand
- Ensuring that the price of electricity reflects the full costs of its generation, including externalized lifecycle environmental, economic, and social costs
- Ensuring that all members of society have access to electricity to meet their basic needs and have the opportunity to benefit from energy efficiency programs, regardless of their incomes

An electricity system constructed on the basis of these principles would seek to maximize energy efficiency, and then employ low-impact renewable energy sources as its option of first resort to meeting remaining electricity demand. Lower-impact non-renewable fuels would then be used to address any remaining demand requirements.

This report examines the feasibility of implementing an electricity system in Ontario that reflects these principles over the next 15 years. In particular, it examines the economic and technical achievability of such a system, and seeks to identify specific policy measures needed to bring about its implementation.

2.2. Methodology

This report approaches the exploration of possibilities for a sustainable electricity system for Ontario through five steps:

1. An examination of the extent to which grid demand might be reduced through a series of policies that encourage households, and commercial/institutional and industrial facilities to adopt the most energy efficient technologies currently available; increased industrial and commercial/institutional cogeneration; and the elimination of electric heating. This examination is undertaken through the following:
   - The proposition of a series of generic policy measures to promote the adoption of energy efficient technologies, cogeneration in the industrial and commercial/institutional sectors, and fuel switching from electricity to natural gas where this is the most efficient option
   - The use of the Canadian Integrated Modeling System (CIMS) computer model developed by the Energy and Materials Research Group at Simon Fraser University to estimate the following: the reduction in electricity consumption that could be achieved from the present to 2020

through the implementation of energy efficiency policies; the incremental investment associated with achieving the 2020 energy savings; the resulting changes in natural gas demand from the adoption of energy efficient technologies and practices; and the net cost per kWh saved through energy efficiency measures

2. The development of an estimate of the reduction in peak electricity demand that would result from the reduction in consumption identified through the CIMS model, and other measures that could be used to shift or reduce 2020 summer and winter peak demand. Load factors are used to estimate the peak demand impacts of the CIMS results. The load-shifting potential of demand response measures such as time-of-day pricing are also considered, along with the peak demand reductions that could be achieved through the use of on-site renewable energy technologies.
3. The review of the potential contributions in terms of power production, peaking potential, and cost of low-impact renewable energy technologies, including existing and new small-scale hydro, wind, and biomass, to meeting the remaining 2020 grid demand. A mix of low-impact renewable energy sources that appears technologically and economically feasible is identified to contribute to meeting this demand.
4. The consideration of the economic, environmental, and social aspects of options to address any remaining grid demand after the optimization of energy efficiency, cogeneration, fuel switching, and the introduction of low-impact renewable energy generation. This may include such options as imports from neighbouring provinces, new or refurbished nuclear generating facilities, combined cycle natural gas, and other new technologies.
5. On the basis of these steps, an overall policy framework for the province is proposed to maximize the adoption of energy efficient technologies, cogeneration, fuel switching, and the use of low-impact renewable energy sources, and to address any remaining supply gaps. This framework considers such factors as financing mechanisms, institutional arrangements, and costs to government of program delivery and administration.

3. Reducing Electricity Consumption

Energy efficient technologies in commercial use today would allow Ontario industry, commercial and institutional establishments, and households to use electricity much more efficiently than is currently the case. The widespread adoption of these technologies in Ontario is essential to meeting the province's future electricity needs in an environmentally and economically sustainable manner, and to ensuring the future competitiveness of the Ontario economy.

The maximization of energy efficiency before considering the construction of new sources of supply offers a series of advantages that make it the option of first choice in the design of Ontario's future electricity system. The provincial government,[51] the Electricity Conservation and Supply Task Force, and others have recognized these advantages, which include the following:

- The ongoing reductions in energy costs for energy consumers. This is particularly important in the context of energy prices that are likely to rise in the future. Investments in energy efficiency can pay for themselves in savings to energy consumers over time.
- The avoided capital costs associated with the construction of new sources of supply and electricity.
- The avoided environmental and health impacts that would otherwise flow from the construction and operation of new sources of supply of electricity. The life-cycle environmental and health impacts of fuel production for non-renewable energy sources, such as fossil fuels and nuclear would be avoided as well.
- The avoided security risks associated with conventional sources of supply, particularly nuclear energy.
- The avoided political risks associated with dependency on fuel sources or energy imports from other jurisdictions.
- The permanent and reliable character of the savings achieved through increased energy efficiency.
- The reduced losses of energy through transmission and distribution systems.
- The improved reliability of the electricity system by lightening the load at the end of the supply/delivery chain, thereby enhancing the reliability of each link in the entire chain.[52]
- The employment benefits flowing from investments in energy efficiency initiatives as opposed to new generation.[53]

A strategy based on the maximization of energy efficiency does carry with it some risks. Energy consumers may not adopt more efficient technologies and practices for a variety of reasons. These include a lack of information about the availability of better options, their costs over conventional technologies, and concerns over the payback times in terms of energy savings against the additional initial investment cost.

However, the alternative strategy of simply attempting to build supply to meet whatever demand emerges as a result of population and economic growth would result in much higher energy costs to consumers. Consumers would have to pay down those capital costs through their energy bills, and may have to forgo the opportunity to make investments to reduce their own consumption in order to do so. This would have serious adverse implications for many sectors of society, including the competitiveness of Ontario industry in relation to other jurisdictions, and the ability of low-income households to meet their basic energy needs.

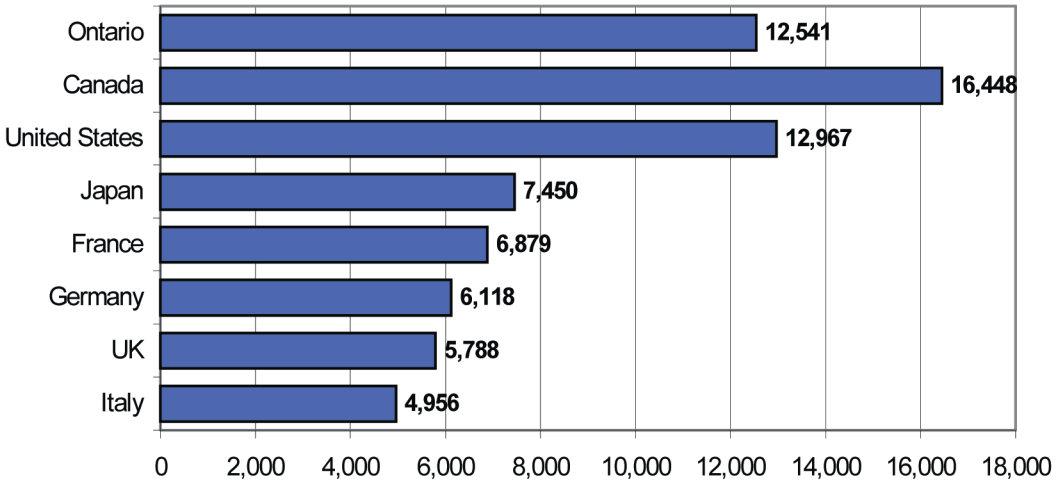
If the same capital that would need to be invested in the construction of new generating facilities is invested in energy efficiency measures, energy consumers are provided with a means of reducing their energy costs, even in the context of rising energy prices. Major investments in energy efficiency could also form the foundation of a wider technological renewal of the Ontario economy, through which the province's competitiveness could be enhanced.

The first question explored in this study is that of how much future electricity demand might be reduced through the adoption of energy efficient technologies and practices. The key to answering this question is examining how Ontario households and businesses

can be persuaded to adopt the more energy efficient technologies and practices that are available, and thereby reduce the underlying risks associated with relying on efficiency improvements to meet demand. Other jurisdictions in North America are facing the same challenges, and a number of lessons from their experiences are applied in the following discussion.[54] California, for example, has reduced peak power demand by 20%, or 10,000 MW over the past 20 years, with a combination of utility demand side management programs, and building and appliance standards.[55]

It is also important to note that while Ontario's levels of consumption of electricity are typical for North America, as shown in **Figure 3.1**, they are very high relative to advanced economies outside North America. Even allowing for differences in geography and economic structure, this suggests that these countries are much more efficient in their use of electricity than is Ontario. This is not surprising, given that many of these jurisdictions have pursued energy efficiency as a central component of their economic strategies for many decades.[56]

Figure 3.1:
Net Electricity Consumption per Capita (KWh), 2000[57]



Source: US Energy Information Administration and UN World Population Prospects, Population in 1999 & 2000.

("Net consumption" is defined as generation, plus imports, minus exports, minus transmission and distribution loss.)

3.1. Approaches to Reducing Electricity Demand

The following approaches are available to reduce electricity consumption on the demand side of the electricity meter.

3.1.1. The Adoption of Energy Efficient Technologies

Many of the most energy efficient technologies or measures available today in each sector of the economy are up to 50% more efficient than those currently in use or those with the highest market share.[58] In most cases, the cost of these technologies is higher than conventional ones, but this incremental cost can be recovered from energy and operating savings in a number of years.

Consumers do not adopt more energy efficient products and technologies or improve the efficiency of their homes and buildings for a number of reasons. These include a preference for lowest first cost rather than lowest life-cycle cost and a preference for familiar products over new ones. Energy efficient technologies can also be harder to find in the marketplace than conventional alternatives.

3.1.2. Cogeneration

New technologies, such as micro-turbines, are making combined heat and power production a feasible option for commercial and institutional buildings as well as industrial facilities at an overall power and heat efficiency of more than 75%.[59] This makes cogeneration an extremely efficient way of using and producing energy.

Producing electricity in this way close to where it is used offers a number of other key advantages:

- The reduction of stress on electricity transmission and distribution systems, while potentially avoiding the need to build expensive new transmission lines.
- The protection of sensitive systems against power disruptions through distributed generation systems so that even if there is a problem with the electricity grid (as on August 14, 2003), customers served by distributed generation sources will still have power.
- Allowing the size of generation systems to be scaled to the power needs of the consumer.
- The provision of shorter project lead-times and easier site approvals.

The main barriers preventing increased use of cogeneration are a shortage of investment capital, the unfamiliarity of cogeneration technologies to potential users, and the lack of net metering that would allow users to buy and sell power to the grid at the same price, as discussed in section 3.2.4.

3.1.3. Eliminating the Use of Electricity for Heating

Efficient gas furnaces and water heaters can now provide space heating at up to 96% and water heating at 80% efficiency, and on a life-cycle basis provide these services at a lower cost than electricity. Eliminating the use of electricity for heat is therefore a very effective and efficient way of reducing the demand for electricity. The main barriers to such a transition in Ontario are a combination of lack of access to natural gas supply in some, particularly rural, areas and the lower initial cost of electric heating systems. This is a particularly serious barrier to low-income households.

3.2. Policy Options to Reduce Grid Consumption

The following types of policies have been used in other jurisdictions to eliminate the barriers that prevent consumers from choosing the most energy efficient technology available each time they replace an existing product or purchase a new one, and to encourage fuel switching and cogeneration.

3.2.1. Minimum Efficiency Codes, Standards, and Labelling of Energy Efficient Technologies

Once an energy efficient technology has gained a significant market share in the new product market, its incremental cost comes down; and there is little penalty to either the energy consumer or manufacturer from regulations that eliminate less-efficient products from the market. This approach has been used successfully to reduce the annual energy consumption of domestic refrigerators by 35% between 1990 and 2000.[60] Energy efficiency codes for buildings in Ontario have also been successful in maintaining a minimum level of comfort and efficiency in housing. The use of codes and standards is a risk-free strategy as the savings are guaranteed.

Labelling high-efficiency products is effective in providing consumers with information on energy performance that helps them make sound buying decisions. Labelling is also effective in helping provide a level playing field for new high-efficiency products that come onto the market.

3.2.2. Financial Incentives for the Most Energy Efficient Technologies and Industrial Processes

When a new more energy efficient product is introduced, and sales are low, there is normally a capital cost barrier that prevents fast user uptake. Financial incentives, like the Ontario sales tax rebate on appliances, help to kick start transformation of the market by temporarily lowering the incremental cost of energy efficient technologies over less-efficient options. Financial incentives lower the payback period on new energy efficient products for energy consumers during the important first phase of market transformation. As sales of new energy efficient technologies increase, the price differential between efficient products and conventional products decreases and often disappears, so that incentives can be phased out. More energy efficient T8 fluorescent lamps, for example, now cost almost the same as less-efficient T12 lamps.

3.2.3. Innovative Financing Programs for High-Efficiency Technologies and Practices

Many potential users of higher efficiency technologies are unwilling or unable to accept the length to time needed for the cumulative savings to cover off the initial additional cost of these technologies over conventional options. These barriers can be overcome through programs that allow customers to purchase energy efficient technologies on a life-cycle basis and pay for the additional cost out of the savings achieved over time. Successful examples of such programs include prime rate loan programs used by utilities such as SaskEnergy to help customers purchase high-

efficiency gas furnaces. Innovative new approaches to financing being proposed include the use of Local Improvement Charges to pay for energy efficiency upgrades to buildings, allowing the cost of long payback improvements to be shared by current and future owners of the property.

3.2.4. Net Metering and Power Purchasing Agreements for Cogeneration

Industrial plants and larger commercial and institutional facilities have few incentives to generate their own heat and power and to sell any excess electricity that they might be able to generate to the grid. These barriers include:[62]

- The lack of grid access for firms with the potential to sell excess electricity. This includes the lack of physical grid connections and the absence of regulatory structures that permit retail customers to sell back to the grid. The lack of net metering also limits the viability of small-scale cogeneration.
- The lack of interconnection standards for electricity projects.
- The discrepancy between the cost of back-up power and the price paid for electricity sold, which reduces the financial viability of cogeneration projects. In some jurisdictions, the cost of connecting to the grid and receiving back-up power from the grid is very high compared with the expected revenue from electricity sales.
- The setting of transmission tariffs on the average cost of transmitting electricity, meaning that the rate doesn't change regardless of how far the electricity is being distributed. This unnecessarily burdens cogeneration projects that are sited close to their electricity customers.
- The hesitancy of plant managers to move away from their core business and begin selling electricity as well. The uncertainty surrounding cogeneration costs can be high for firms unfamiliar with the technology, thereby discouraging investment.

These barriers can be removed by introducing grid access standards and a net metering regime under which power is sold to the grid at the same price or higher than the power purchased by the facility in recognition of the efficient use of natural gas use in cogeneration plants. Long-term power purchase agreements for cogenerators can provide the long-term financial stability needed to justify cogeneration investments in larger facilities.

3.3. Using the CIMS Model to Evaluate Demand Side Policy Options

To test the impact of power consumption reduction policies, and to get a firmer idea of the incremental cost of efficiency improvements to government and consumers, some typical policy scenarios were tested using the Canadian Integrated Modelling System (CIMS) model developed by the Energy and Materials Research Group (EMRG) at Simon Fraser University. The CIMS model provides a forecast of energy use by technology, end-use, and sector in five-year increments, together with the end-use equipment investment associated with each forecast.

The results allow the analyst to test different policy scenarios and estimate the energy savings that each might produce over the long term. The associated costs allow efficiency "supply curves" of cost-per-unit savings against size of savings to be derived from the CIMS model results. These supply curves illustrate the most cost effective end-uses and allow comparison with supply side costs.

3.3.1. The CIMS Model

The CIMS model estimates future energy demand by simulating the addition and replacement of energy using "stock"—industrial process equipment, electric motors, commercial lighting equipment, residential appliances, etc. The addition of new stock is linked to forecasts of macroeconomic parameters such as industrial production, commercial floor space, and housing starts. Stock replacement is determined by the life of the piece of equipment, or its availability. CIMS also simulates a "competition" among technologies that can meet the demand for new or replaced stock. The distribution among the competing technologies depends on its capital cost, operating cost, and various parameters representing consumer preference.[63]

Energy demand is then estimated by multiplying the stock number of each technology installed at any time by their energy use per unit. CIMS also aggregates the investment in the stock. The model allows the analyst to modify parameters to simulate policies that add or remove technologies, change energy prices, or manage consumer choice. By running a base case (business as usual) forecast followed by a forecast with the policy parameters changed, the analyst can estimate the reduction in energy use resulting from the policy change as well as the additional investment required to achieve these savings.

Because CIMS treats each energy end-use separately,

the analyst can also construct a "supply" curve of energy efficiency measures showing which groups of measures are the most cost effective.

3.3.2. How the CIMS Model Was Used to Simulate Energy Efficiency Policies

The CIMS model has been used for several other studies in Ontario, and has been calibrated to 2000 electricity use as reported by Statistics Canada. Capital costs, operating costs, and energy use per unit have been incorporated into the model for most technologies currently in use today. User preference parameters in the form of perceived discount rate have been set to simulate today's user choices of lowest first cost. Cogeneration is constrained to provide power only within industrial plants (i.e., power is not sold to the grid).

The CIMS model uses the forecasts for electricity and gas prices for Ontario prepared by Natural Resources Canada (see **Tables 3.1** and **3.2**) to compute the life-cycle costs of competing technologies.

Table 3.1: Ontario Electricity Price Forecast (¢/kWh), 2000–2020[64]

	2000	2005	2010	2015	2020
Commercial	8.30	8.50	9.22	9.98	10.79
Industrial	6.30	5.38	5.83	6.31	6.82
Residential	10.00	10.24	11.11	12.03	13.00

Table 3.2: Ontario Natural Gas Price Forecast ($/GJ), 2000–2020[65]

	2000	2005	2010	2015	2020
Commercial	5.25	5.79	6.41	6.97	7.61
Industrial	3.61	3.97	4.40	4.76	5.18
Residential	6.37	7.01	7.76	8.46	9.25

The prices in Tables 3.1 and 3.2 are considered reasonable expectations in Ontario. While until April 1, 2004, the residential tariff was 4.3 cents per kWh, once other fixed and variable charges were added, the Ontario consumer was effectively paying in the range of 10 cents per kWh.[66]

To simulate the types of electricity reduction policies described earlier in this section, changes were made to the CIMS model parameters:

1. To simulate **net metering for cogeneration**, the constraints that CIMS uses to restrict cogeneration were removed. This allowed generation of power up to levels matching the steam demand of the industry, with the excess electricity being supplied to the grid.
2. To simulate **financial incentives** (such as the removal of sales taxes), the capital cost of the most energy efficient technology used for each energy end-use, high-efficiency gas heating systems, and cogeneration systems in CIMS were all reduced by 8%.[67] CIMS includes most of the high-efficiency technologies and cogeneration systems available on the market today, and these were designated as the "target" technologies for this policy.[68] In effect, the simulation reduced the effective payback period for energy efficiency, cogeneration, and fuel switching investments for the user by reducing their first costs.
3. Under normal circumstances, energy consumers will give preference to technologies with the lowest first cost, and only invest in energy efficiency if the paybacks are very short. CIMS simulates this behaviour by using high user discount rates, which minimize the importance of fuel and operating costs in any decision. To simulate market transformation programs that remove these barriers through **innovative financing** and other means, the user perceived discount rates in CIMS for the targeted

technologies were reduced to the financial "hurdle" rate[69] in each sector. These hurdle rates were set at 12% for the industrial sector, and 8% for the residential and commercial sectors. In effect, the reduction of discount rates simulates a situation where potential users of an energy efficient technology are provided the means to pay for the technology as they achieve the savings. This leads to users investing in measures with longer payback periods than they normally would.

4. Minimum standards were not explicitly simulated, but the model results were used to identify the year when each of the targeted technologies gained a significant market share (>50%) and therefore determine when a standard could be imposed without penalizing consumers or industry.

The forecast electricity consumption by sector assuming no change in CIMS parameters (business as usual) was estimated as shown in **Table 3.3**.

Table 3.3: CIMS Electricity Consumption Forecast by Sector—Business as Usual, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	36,674	38,430	40,535
Commercial/Institutional		55,279	64,885	76,226	89,489
Industrial	Process	12,709	12,749	12,912	13,049
	Auxiliary	33,440	33,950	36,072	38,269
	Cogeneration	(464)	(497)	(535)	(567)
TOTAL		138,890	147,761	163,105	180,775

There are some discrepancies between the CIMS forecasts, which are based on 2000 Statistics Canada figures and Natural Resources Canada forecasts, and those of the IMO and Electricity Conservation and Supply Task Force (see **Table 1.4**). These discrepancies are particularly evident in the early years of the forecast. This is due to differences in data reported to the two different sources by Ontario energy users, and in the assumptions of macroeconomic parameters over the next 15 years. However, the differences are not large enough to affect the results of this analysis.

3.4. The CIMS Results

Four CIMS simulations were carried out with the following policy assumptions:

Simulation 1: The removal of barriers to cogeneration

Simulation 2: The provision of financial incentives + the removal of barriers to cogeneration

Simulation 3: The reduction of discount rates (simulating the impact of innovative financing programs) + the removal of barriers to cogeneration

Simulation 4: The provision of financial incentives + the reduction of discount rates + the removal of barriers to cogeneration

The individual runs showed that lowering discount rates resulted in the largest reduction in electricity consumption, followed by cogeneration and financial incentives. This appears to be a reasonable result since the lack of means to finance the higher cost of energy efficient technologies out of the savings applies to all sectors and end-uses. Financial incentives alone provide a benefit only if they bring the cost of the energy efficient technology close to that of conventional technologies. Cogeneration only applies to industry and larger commercial and institutional buildings. The three measures are not additive, but each tends to improve the chances of the others being successful. A small financial incentive program, for example, will increase the likelihood of a consumer taking advantage of a financing program.

The following analysis considers the consumption reduction associated with the combined policies. Full details of the CIMS model simulations and results are provided in a separate report by M. K. Jaccard and Associates in Appendix 1.

3.4.1. The Impact of Modelled Policies on Electricity Consumption

The CIMS electricity consumption forecast by sector with all of the three policy changes in place is shown in **Table 3.4**.

Table 3.4: CIMS Electricity Consumption Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	30,542	27,277	26,494
Commercial/Institutional		55,279	47,623	40,874	39,201
Industrial	Process	12,709	11,952	10,863	10,058
	Auxiliary	33,440	32,060	33,263	34,570
	Cogeneration	(464)	(1,282)	(2,173)	(3,047)
TOTAL		138,890	120,895	110,104	107,276

Energy savings achieved with the policy changes in place in each sector relative to the business-as-usual forecast are shown in **Table 3.5**.

Table 3.5: CIMS Energy Savings Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential			6,132	11,153	14,041
Commercial/Institutional*			17,262	35,352	50,288
Industrial	Process		797	2,050	2,991
	Auxiliary		1,890	2,809	3,699
	Cogeneration		786	1,638	2,480
TOTAL			26,867	53,002	73,499

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The CIMS results show that with the policy assumptions built in to the model for each sector, energy users would significantly change their purchasing habits with respect to energy-using equipment and processes. These changes would reduce business-as-usual electricity consumption by 73,500 GWh/yr (from 180,775 to 107,276 GWh/yr) by 2020. This amounts to a 40% reduction against the business-as-usual consumption forecast.

The electricity savings result from three types of technological and behavioural changes:

1. The adoption of the most energy efficient technologies instead of conventional products in all sectors
2. The expansion of cogeneration in the industrial and commercial/institutional sectors as energy consumers take advantage of the efficiencies offered by combined heat and power, and generating power through cogeneration and micro-turbines instead of buying from the grid
3. A shift from electricity to natural gas for heating in the residential and commercial/institutional sectors

These changes would be achieved as energy users take advantage of financial incentives that reduce the capital cost of energy efficient or non-electric technologies, and innovative financing that would allow them to make purchasing decisions more on a life-cycle cost rather than a first-cost basis.

The overall results provided by the CIMS model should be viewed as an example of what could be achieved using the types of policies simulated. Actual strategies that might be used to obtain these savings are outlined in section 6 of this report.

The CIMS results are conservative in nature. Many of the savings and cost advantages of new innovative approaches to energy efficient building design, such as integrated design, high-efficiency lighting management, and radiant cooling have yet to be built into the CIMS model.

3.4.2. The Impact of Energy Efficiency, Increased Cogeneration, and Fuel Switching on Natural Gas Consumption

One of the major issues that has emerged in the debates over future electricity supply in Ontario is the question of the impact of different energy efficiency and supply options on natural gas consumption.[70] The CIMS estimates of the net changes in natural gas consumption resulting from fuel switching and cogeneration, less the efficiency gains from using more energy efficient gas-using products are shown in **Table 3.6**.

Table 3.6: CIMS Forecast of the Impact of Simulated Policies on Natural Gas Consumption, 2005–2020

Sector		Increases in Natural Gas Use—PJ			
		2005	2010	2015	2020
Residential			(23)	(38)	(45)
Commercial/Institutional*			52	118	176
Industrial	Process		2	4	6
	Auxiliary		0	0	1
	Cogeneration		(3)	(5)	(8)
TOTAL			28	79	130

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The CIMS results show that natural gas use in the residential sector would be significantly reduced by the policy changes. While there would be a switch by energy consumers to natural gas for heating, many of the measures that improve electricity efficiency also improve gas efficiency. The same thing happens in the industrial sector, where there would be an increase in the amount of cogeneration, but this would be more than offset by using more gas-efficient cogeneration technologies. In the commercial/institutional sector, the increase in cogeneration would not be fully offset by increases in efficiency, with the result that there would be a net increase in gas use in the sector.

The net increase in gas consumption over business-as-usual by 2020 would be 130 PJ for a total of about 1,210 PJ per year. This is an increase of 43% over Ontario's 2001 natural gas consumption of 842 PJ. However, only about 12% of this increase is attributable to the impact of fuel switching, increased cogeneration, and other technological and behavioural changes flowing from the policy measures tested through the CIMS simulations.

3.4.3. The Costs of Energy Efficiency Improvements

Total undiscounted additional investments required to achieve savings identified through the CIMS analysis between 2005 and 2020 are shown in **Table 3.7**. The figures reflect the additional (undiscounted) investment costs (i.e., incremental investments over business-as-usual) resulting from stock changes in targeted technologies and their direct competitors.

Table 3.7: CIMS Forecast of Total Incremental Investments Needed to Achieve Projected Electricity Savings

Sector		Total Incremental Investments 2005–2020
		In millions of dollars (undiscounted)
Residential		6,633
Commercial/Institutional*		13,494
Industrial	Process	770
	Auxiliary	225
	Cogeneration	365
TOTAL		21,487 = $21.5 billion

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The figures in Table 3.7 show the additional investment by both energy users and government (through financial incentives) in new more-efficient equipment and cogeneration over the 15-year period covered by the CIMS analysis.

However, it is critical that the costs be considered in the context of the reduced electricity costs that consumers will enjoy as a result of investing in higher efficiency technologies. In some cases, the investments will result in reduced gas consumption and lower maintenance costs as well.

This is illustrated in **Table 3.8**, produced directly from the CIMS model results. Table 3.8 provides a comparison of the incremental investment in energy efficient technologies and practices, the reduction in operation and maintenance costs resulting from these investments, and the net savings in energy costs assuming the energy prices given in Tables 3.1 and 3.2.

Table 3.8: Forecast Incremental Costs Associated with Achieving 2020 Energy Savings (discounted to 2004)

Sector	Incremental Costs Associated with Achieving 2020 Savings In millions of dollars (discounted to 2004)			
	Investment	Operation and Maintenance	Energy	Total
Industrial	829	273	(1,255)	(153)
Residential	7,220	(45)	(6,174)	1,001
Commercial/Institutional*	10,211	1,345	(11,782)	(226)
TOTAL	18,260	1,573	(19,211)	622

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

As Table 3.8 shows, the savings flowing from reduced energy consumption almost pay for the additional cost of the adoption of higher efficiency equipment. In fact, there are net benefits to commercial/institutional and industrial energy consumers.

Table 3.8 also shows a cost to residential consumers of energy efficiency investments of approximately $1 billion. This cost would amount to just over $90 per resident, spread over a 15-year period, or approximately $6 per person per year. However, in addition to energy savings, investments in the residential sector would carry with them significant co-benefits in terms of improvements in overall housing quality.

In essence, the savings in energy costs resulting from reduction in energy consumption will pay for more than 96% of the capital costs of the adoption of more energy efficient technologies over the long term. The net effect would be that even in the context of rising electricity and gas prices, the electricity costs to households and businesses would remain roughly the same as they are now, provided that consumers make the necessary investments in more energy efficient technologies and practices.

It is also important to note that the estimates of the savings resulting from investments in energy efficiency only consider the direct cost savings resulting from reduced energy use. They do not consider the economic, health, environmental, and social co-benefits that would flow from these investments. These co-benefits include the avoided environmental and health impacts of the construction and operation of generating facilities, improved housing quality, and the increased competitiveness of businesses and industries resulting from their more efficient use of energy resources.

In the case of health and environmental benefits, for example, the Ontario Medical Association has estimated that the total annual health costs associated with poor air quality in Ontario, to which, as described in section 1.3 of this report, the current electricity supply mix is a major contributor, at $9.9 billion per year.[71] The reductions in these costs that would flow from the avoided impacts of electricity generation arising from investments in energy efficiency measures would therefore be substantial.

A more detailed discussion of the costs of individual types of energy efficiency measures is provided in section 3.4.5.

3.4.4. Stock Turnover and Minimum Energy Efficiency Standards

Table 3.9 shows the market share of new stock of each of the targeted energy efficient technologies under the

policy regime simulated through the CIMS analysis and the market share of total installed stock in 2010 and 2020.

The table shows that by 2010, significant fuel switching, uptake of the targeted energy efficient technologies, and cogeneration has taken place. This would allow minimum energy efficiency standards and codes to be raised to the levels of these technologies soon after 2010 without penalizing manufacturers or consumers. This would have the effect of allowing natural stock turnover to achieve complete market transformation to energy efficient technologies by 2020. As soon as the energy efficiency standards are in place, the financial incentives can be discontinued or shifted to newer and even more energy efficient technologies. This would not change the total incremental investment needed, but greatly reduce the government share of the cost once market transformation has begun.

3.4.5. The Most Cost-Effective Ways to Reduce Electricity Use

It is also interesting to consider the relative contribution and cost of some of the individual technologies contributing to reduced electricity use. **Table 3.10** was generated from the CIMS results and provides the estimated cost per kWh saved[72] for each technology end-use and the GWh/yr saved in that end-use over the 15-year period 2005–2020. The table illustrates how the "supply" cost of most energy efficient technologies lies at between 0 and 7 cents per kWh saved. The table also shows how some energy efficient technologies are more cost effective than others and where the greatest impact can be obtained from energy efficiency programs.

It is important to note that all of the different end-uses are not independent of each other, and the costs and savings generated by one group of technologies is often contingent on another group. The results show that residential appliances and fuel switching, commercial/institutional building shell and heating, ventilation and air conditioning, and lighting, and industrial drive powers should receive priority attention. The costs of saved energy found in this analysis compare well with other recent studies of conservation/demand side options.[73] In section 5, we compare these costs per kWh with the costs of supply options.

The high cost of new single family home space heating improvements reflects the fact that the these improvements have the effect of reducing natural gas consumption significantly, but have a limited impact on electricity use.

Table 3.9: CIMS Forecast of Market Share of Targeted Energy Efficient Technologies, 2010–2020

Technology End-use or Sub-Sector	Market Share of Targeted Energy Efficient Technologies		
	New Market Share in 2010	Total Market Share in 2010	Total Market Share in 2020
Residential			
Clothes Washers	100%	53%	100%
Dishwashers	89%	45%	89%
Other Hot Water Use	77%	61%	70%
Clothes Dryers	100%	43%	97%
Ranges	100%	33%	91%
Freezers	99%	32%	90%
Lighting	100%	100%	100%
Refrigerators	100%	41%	97%
Air Conditioners	100%	17%	44%
New Homes	65%	34%	52%
Existing Home Retrofits	10%	3%	11%
Furnace Air Fans	100%	63%	100%
Water Heaters	86%	58%	76%
Commercial/Institutional			
Office Equipment (Plug Load)	43%	20%	43%
Hot Water	100%	76%	100%
Cooking	100%	71%	100%
Refrigeration	97%	45%	97%
Lighting	99%	52%	81%
Large Retail—New	8%	4%	6%
Hospitals/Nursing Homes—New	73%	27%	59%
Hotels/Motels—New	95%	35%	75%
HVAC Systems/Cogeneration	100%	27% to 41%	71% to 84%
Industrial			
Motor Drives	35%	34%	36%
Fans and Blowers	77%	23%	50%
Conveyors	34%	29%	34%
Compressors	76%	55%	74%
General Pumping	91%	86%	91%
Slurry/Stock Pumping	100%	92%	100%
Precision Pumping	98%	90%	98%
Shaft Drive Motors	58%	36%	47%
Lighting	96%	49%	74%
Space Heating	84%	47%	67%

Table 3.10: Estimated Cost per kWh Saved by End-Use

Technology End-use	Incremental Capital Cost of Efficiency ($/kWh saved)	Cost of Additional Natural Gas ($/kWh saved)	Electricity Saved through Efficiency, Fuel Switching and Cogeneration (GWh/yr)
Residential			
Lighting	$(0.006)		832
Furnace Air Fans	$(0.004)		359
Post-1960 Single Family Homes—Space Heating	$0.001	$(0.079)	373
Pre-1960 Single Family Homes—Space Heating	$0.003	$0.007	971
Apartments—Space Heating	$0.016	$0.021	1,540
Ranges	$0.022	$(0.014)	1,702
Hot Water Heating	$0.032	$(0.038)	4,738
Freezers	$0.053		385
Other Housing—Space Heating	$0.057	$(0.279)	352
Clothes Dryers	$0.061	$(0.031)	338
Clothes Washers	$0.065		660
Dishwashers	$0.081		746
Air Conditioners	$0.104		246
Other Appliances	$0.142		0
Refrigerators	$0.156		622
New Single Family Homes—Space Heating	$0.663	$(0.624)	176
Commercial/Institutional			
Hot Water	$(0.000)	$0.035	4,945
Cooking	$(0.000)	$0.093	1,088
Shell and HVAC	$0.024	$0.042	30,040
Lighting	$0.024		9,970
Refrigeration	$0.097		1,419
Office Equipment (Plug Load)	$0.375		361
Industry—Auxiliary			
Lighting	$(0.006)		22
Space Heating	$(0.000)	$0.060	61
Conveyors	$0.000		145
Direct Drive	$0.000		1,356
Pumps	$0.004		554
Fans and Blowers	$0.005		219
Compressors	$0.013		1,341
Industry—Process			
Chemicals	$0.002		238
Metals	$0.002	$0.008	239
Pulp and Paper	$0.024		1,777
Petroleum Refining	$0.028		127
Iron and Steel	$0.046	$0.063	488

3.5. Estimating Peak Demand Reduction from Efficiency Improvements, Increased Cogeneration, and Fuel Switching

The reduction in peak demand associated with the efficiency gains forecast through the CIMS analysis in section 3.4 were estimated using load factors.

The system peak load factor may be defined as average demand divided by peak demand.

Average demand (MW) = Total consumption (GWh) x 1,000/Hrs per year
Peak Demand = Average Demand/Peak Load Factor

Applying this formula to the IMO forecasts of electricity consumption and peak demand,[74] the average system summer peak load factor for the Ontario grid is about 68%. Applying this factor to the 73,400 GWh of electricity savings realized across all sectors shown in Table 3.5 through the proposed policies produces a peak demand reduction of 12,300 MW by 2020. As shown in **Table 3.11**, this would reduce expected summer peak demand in 2020 from 30,000 MW to 17,700 MW. This estimate is conservative, as the majority of the GWh savings would be achieved in the residential and commercial/institutional sectors where the peak loads are the highest.

Determining the separate effects of the efficiency savings on individual summer and winter peaks would require a more detailed analysis of each end-use. For this analysis it is assumed that the estimated peak demand reduction would apply to both summer and winter.

No additional policies would be required to achieve these reductions. The phasing out of electric heat in favour of gas will have a very positive effect on the winter peak. Priority could also be given under the electricity efficiency strategy described in section 6.4 to those technologies identified in Table 3.9 that would achieve the highest peak demand reduction, such as commercial/institutional building HVAC and water heating systems, and household ranges.

Table 3.11: Estimated Reduction in Summer Peak Demand from Efficiency, Fuel Switching, and Cogeneration

	2010 Peak (MW)	2015 Peak (MW)	2020 Peak (MW)
IMO Forecast for Summer Peak Demand	27,800	28,700	30,000
Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(8,900)	(12,300)
Remaining Summer Peak Demand	23,300	19,800	17,700

4. Demand Response and Peak Load Shaving

This section assesses the additional reduction in peak demand that could be achieved through demand response measures, such as time-of-day pricing and smart metering. The additional reduction that could be achieved through special demonstration programs specifically designed to shave peak demand, such as a 1,000 MW solar photovoltaic (PV) roof program, are also considered.

4.1. Demand Response Measures

Demand response measures are those in which power users are encouraged to not use power at peak periods. This is done through pricing mechanisms designed to encourage customers to delay or manage power-using activities on an hourly or daily basis at critical peak periods. It can also be carried out through interruptible or ripple supply rates, where users agree to have non-key loads such as water heaters and battery charging shut off or supplied intermittently during peak periods.

Demand response measures should not be confused with measures that encourage power consumption and load reduction through improved equipment efficiency as described in section 3.

The April 2003 "Blueprint for Demand Response in Ontario," prepared by Navigant Consulting for the IMO, indicates that up to 10% of Ontario's peak demand could be shifted through demand response measures.[75] The recommended measures include widespread use of "interval" meters for all types of customer throughout the province that would allow customers to choose a fixed price for power or modify their electricity use in response to price signals from their utilities.

Assuming that efficiency measures, fuel switching, and cogeneration reduced 2020 peak grid demand by 12,300 MW (from 30,000 MW to 17,700 MW) as discussed in section 3.5, demand response measures could reduce this figure by an additional 1,770 MW as shown in **Table 4.1**.

4.2. Load Shaving through On-site Generation

Several jurisdictions in the United States and Europe have implemented programs that encourage the use of on-site grid-connected solar PV systems incorporated into the roofs of existing and new buildings, or buildings that otherwise provide a portion of their own power from renewable energy sources. In Europe, feed-in tariffs and other innovative means are used to finance solar PV programs so that the cost is internalized within the grid system (paid for by all customers) rather than through a direct subsidy.[76] Countries such as Germany have supplemented these measures with major solar PV programs. A German 100,000 Roof Photovoltaic Programme was introduced in 1999 and is administered by the German Credit Institution for Reconstruction (*Kreditanstalt für Wiederaufbau* [KFW]). The program supports the installation or extension of photovoltaic systems with a peak nominal power of at least 1 kWp. The program offers a special zero-interest loan with a repayment period of 10 years and up to two starting years without credit repayment.[77]

These solar PV programs have many key benefits. These include:

- Providing reductions in summer peak demand. Air conditioning loads that drive summer peaks reach their highest levels during the day when solar radiation is high and solar PV systems deliver their maximum output.
- Providing a jump-start to the solar PV industry so that economies of scale can be achieved, thereby reducing costs.
- Providing greater visibility for renewable energy.
- Allowing energy users who wish to generate their own power to do so.
- Providing end-of-line stability to power distribution systems to maintain power quality.

Ontario's summer peak appears to be rising faster than the winter peak due to the increasing air conditioning load.[78] However, Ontario also has a very good

summer solar resource, and there should be sufficient roof space in major cities like Toronto to mount large numbers of solar PV systems. The cost of solar PV systems is still high, but the potential is very large. A 1,000 MW solar roof program involving up to 200,000 buildings in Ontario, coupled with the improved grid access policies described in section 6.4 would lay the foundation for cost reduction and a major contribution from solar electricity beyond 2015. A solar roofs program would provide the much needed peak demand reduction as the summer peak grows in the province as well as providing the other benefits listed above.

One kW of PV capacity will provide one kW output at full-sun conditions at noon. If it is assumed that average summer conditions during the summer peak are equivalent to 75% full sun, 1,000 MW of solar PV could be expected to reduce peak demand by about 750 MW and produce about 2,500 GWh/yr of power.

4.3. Estimating Remaining Grid Peak Demand

Section 3 of this study demonstrates that it is reasonable to assume that electricity consumption from the grid in Ontario could be reduced by 73,500 GWh/yr against business-as-usual forecasts by 2020 through a combination of the adoption of existing energy efficient technologies, cogeneration, and fuel switching. As discussed in section 3.5, this translates into a reduction in peak demand of 12,300 MW.

Demand response measures are estimated to be able to reduce peak demand by a further 10%, or approximately 1,770 MW, by 2020. An on-site generation solar roof program could reduce summer peak demand by a further 750 MW by 2020. The total estimated peak demand reduction and resulting net grid peak demand are shown in Table 4.1.

Table 4.1: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

As Table 4.1 shows, net summer peak demand could be reduced by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

5. Meeting Residual Grid Demand

5.1. Remaining Grid Demand

Table 5.1 summarizes the remaining grid requirements in Ontario assuming the reductions in demand outlined in sections 3 and 4.

Table 5.1: Net Grid Requirements, 2005–2020

	GWh/yr	Winter Peak (MW)	Summer Peak (MW)
2005	153,000	25,500	26,300
2010	136,000	19,200	20,700
2015	117,000	15,600	17,400
2020	104,000	13,900	15,200

These figures indicate that there would be a need to provide a reliable base load of approximately 13,000 MW and additional capacity to meet another 2,000 MW of mid-load and peak demand by 2020.

Ontario has a range of potential supply options to meet this remaining grid demand. In addition to the province's existing hydroelectric facilities, these include traditional non-renewable energy sources, such as nuclear power, and fossil fuels, such as coal and natural gas. New renewable sources of supply, including wind, hydroelectric power, and the use of methane from municipal landfills and the anaerobic digestion of municipal, agricultural, and industrial wastes (biomass) will also be available.

5.2. Renewable Supply Options

In accordance with the sustainable energy path laid out in section 2, renewable energy sources, such as wind, hydro, and biomass, are examined as the supply options of first resort for the purposes of this study. This reflects the following features of these sources:

- Their low environmental and health externalities relative to conventional sources. Wind energy, for example, generates no emissions other than those associated with the manufacturing of generating equipment.[79]
- Their low operating costs relative to conventional supply, given that the underlying energy sources, such as wind, run-of-river water, and municipal and agricultural wastes are available at little or no cost.
- Renewable sources do not require the import of fuels or electricity from outside of Ontario. Therefore, they provide a higher security of supply than conventional supply options. Renewable energy sources are also unaffected by the shifts in the costs of conventional fuels, such as coal and natural gas, that may occur due to international demand or market conditions that are beyond the control of the Government of Ontario.
- Their low security risks relative to some types of conventional supply, particularly nuclear energy.
- The distribution of supply among a larger number of technologically and geographically diversified sources reduces the risks and impacts associated with the failure of particular technologies, or upsets and breakdowns at individual large, centralized generating facilities.

The following analysis of renewable energy options reviews wind, hydro, and biomass power sources and

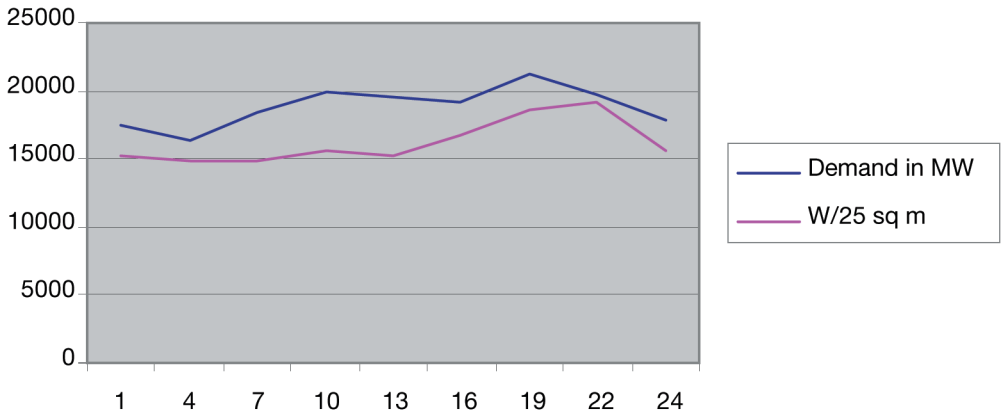
their potential contribution to annual electricity supply and meeting peak demand. The analysis is based on the best currently available information sources on renewable energy in Ontario.[80] It is important to note that the overall state of the estimates of the potential contributions from low-impact renewable energy sources in Ontario is poor, as only very limited work has been done in this area since the time of the Ontario Hydro Demand Supply Strategy in the early 1990s. Some of the available technologies, particularly wind, have undergone major advancements since then.

5.2.1. The Ability of Renewable Energy Sources to Meet Peak Demand

Some renewable energy sources have limited dispatch capability (e.g. run-of river hydro). Others, such as wind, are intermittent but match peaks in demand quite. There is a good correlation, for example, between Ontario's peak electricity demand and the characteristics of Ontario wind speeds, as shown in **Figures 5.1** and **5.2**. Hydro with storage capacity can be used for both base load and peaking, although it is associated with potentially higher environmental impacts. Finally, modern electronic control and power regulation equipment, and accurate weather forecasting allow grid dispatchers to forecast power outputs from renewable energy sources (such as solar, wind, and run-of-river hydro) and dispatch hydro storage and natural gas capacity as needed. With an effective integration and dispatch strategy in place, therefore, much higher percentages of supply from renewable sources are possible.

Figure 5.1: Ontario Electricity Demand vs. Wind Supply for July 18, 2001[81]

Figure 5.2: Ontario Electricity Demand vs. Wind Supply for January 18, 2001[82]



5.2.2. Hydroelectric Power Generation

Current hydroelectric capacity in Ontario is 7,665 MW, mostly located on the Niagara, St. Lawrence, and Ottawa rivers, and in northern Ontario. Some locations are run-of-river, while in other locations there is significant storage capacity. Power can be dispatched from those facilities with storage capacity in response to demand within certain reservoir level limits.[83]

Ontario Hydro/Ontario Power Generation (OPG) have proposed the addition of diversion tunnels and a new underground generating station with a capacity of 600 MW to the existing generating facilities at Niagara Falls.[84] As shown in **Table 5.2**, the Ontario Waterpower Association has estimated that there is a total of between 1,200 MW and 4,000 MW of additional waterpower resources in Ontario that could be developed at between 6 and 8 cents per kWh.[85]

Table 5.2: Ontario Waterpower Potential for Development[86]

Source	Capacity (MW)	Energy (GWh)
Known Developable Sites	200 to 300	1,000 to 1,500
Re-developments at Existing Facilities	600 to 1,300 (equivalent)	2,000 to 3,000
Upgrades—Re-powering and Efficiency Improvements	200 to 400	1,000 to 1,500
Additional Development Potential	200 to 2,000	1,000 to 10,000
TOTAL	1,200 to 4,000	5,000 to 16,000

On this basis, it is reasonable to assume that a total of 2,000 MW of new hydroelectric supply could be brought on line by 2020, bringing total capacity, considering the 7,665 MW already in place, to 9,665 MW. A certain portion of this capacity could be dedicated to providing back-up power for provincial wind capacity. It was assumed that the capacity factor for any new hydro facilities would be approximately the same as existing facilities.87 However, the contribution to peak supply would be slightly lower than existing plants, due to the high portion of run-of-river facilities assumed to be in the new capacity.

5.2.3. Large-Scale Wind Power Generation

The technologies for generating electricity through wind power have undergone an enormous transformation over the past decade, resulting in a dramatic reduction in the costs of wind-generated electricity.[88] Large-scale installations of wind power generation units are becoming more common in Europe and the United States. The total installed and forecast wind power generating capacity in selected leading countries is shown in **Table 5.3**.

Table 5.3: Installed and Forecast Wind Power Generating Capacity, Selected Countries[89]

Country	Installed Capacity (MW) 2000	Forecast Capacity (MW) 2005
Germany	6,107	14,307
Spain	2,836	11,236
Denmark	2,341	3,841
United States	2,610	7,360

Wind farms in Ontario must be located close to the grid. This implies locations in southern Ontario and parts of northern Ontario where grid access will be feasible. The grid-accessible portion of the province is estimated to have a geographic area of over 300,000 sq. km. This is approximately the same land area as Germany, where there is 7,500 MW of installed wind power generating capacity.[90] Ontario has abundant wind resources, and in its 2001 report, the Ontario Wind Power Task Force (OWPTF) estimated potential onshore wind capacity on Crown land in Ontario at between 2,000 and 7,500 MW.[91] Most of this capacity is on the shores of the Great Lakes where wind regimes are high enough to make wind a commercially viable power option at current wind turbine costs of approximately $1.5 million per megawatt. [92]

Private developers have indicated that in the early stages of Ontario's wind energy development, the net present realized cost of wind energy from a viable site is 8 to 10 cents/kWh.[93] The factors that have the largest impact on price are the wind regime, which in Ontario is good, but not as good as on Canada's coasts or on the prairies, and the foreign exchange needed to purchase most of the turbine equipment.[94] The establishment of a wind equipment manufacturing industry in the province would reduce the latter costs.[95]

The prices of wind power systems themselves have been falling steadily over the past 20 years. Recent modular installations of 1 MW units in the North Sea off the UK and Denmark show that even lower costs can probably be achieved.[96] The OWPTF did not explicitly estimate the offshore potential in the Great Lakes, but states that it would be "significantly greater" than the 7,500 MW of onshore potential.[97] It would seem plausible therefore that 7,000 MW of wind power could be installed onshore and offshore in Ontario by 2020. The minimum capacity factor for wind systems expected in Ontario is 30%[98] so that 7,000 MW would generate 18,396 GWh/yr of electricity.

The OWPTF also showed that wind generator output could be expected to match both daily and seasonal peak demand.[99] Wind speeds increase in the afternoon in both summer and winter, coinciding with the evening peak. Wind speeds also increase with lower temperatures and match the higher loads that occur during colder weather.[100] Conservatively, therefore, 7,000 MW of wind power capacity should be able to contribute at least 3,000 MW during periods of peak demand.

Even though the match between peak demand and wind speed is good, there will still be some occasions when wind power generator output will need to be supplemented by dispatchable sources, such as hydro with storage or natural gas turbine peaking units. There will be a need to designate a certain proportion of the hydro capacity in Ontario as a complementary source to wind, integrating outputs from the two sources to provide an equivalent base load source. This coordination should be made easier through advances in wind forecasting, which will allow the outputs from wind farms to be predicted several days ahead. Diversifying the location of wind power farms throughout the Great Lakes will also reduce the percentage of time that wind power will need to be supplemented with hydro.

5.2.4. Landfill, Sewage, and Anaerobic Waste Digestion Gas Capture and Generation (Biomass)

Methane generated in landfills, and from the anaerobic digestion of sewage sludge, and municipal and agricultural wastes can be collected and burned as fuel to generate electricity.

It has been estimated that over 100 MW of generating capacity could be provided through landfill gas recovery and combustion in Ontario.[101] The largest installed generating capacity in Canada is 30 MW at the City of Toronto's former Keele Valley landfill.[102] Large, new, or expanding Ontario municipal waste landfills have been required to install landfill gas recovery facilities since 1998. [103]

The OWPTF estimated that a total of between 200 MW and 500 MW of capacity might be provided through the use of methane from the anaerobic digestion of various waste streams, at a cost of between 6 and 9 cents/kWh.[104] Some additional supply may be provided through industrial cogeneration using materials such as wood or agricultural wastes as fuel as well.

On this basis, it is estimated that 800 MW of capacity from landfill and waste digestion generated gas combustion and agricultural and wood waste combustion might be installed by 2020. These sources are assumed to have quite a high capacity factor, and deliver at least 50% of capacity at peak times. Therefore, 800 MW of capacity was assumed to deliver 5,600 GWh/yr and 375 MW at peak periods.

5.3. Summary of Renewable Energy Potential and Remaining Demand

Table 5.4 provides a possible demand and supply mix in which coal is phased out by 2010 and nuclear power by 2020, incorporating the estimated contributions available from renewable energy sources outlined in section 5.2.

Table 5.4: 2010–2020 Demand and Supply Mix with Efficiency and Low-Impact Renewable Energy Sources[105]

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
Remaining Base Load Requirement	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

5.4. Supply Options to Meet Remaining Grid Demand

Table 5.4 shows that even with the contributions from efficiency programs and low-impact renewable sources of supply, approximately 4,200 MW of new base load capacity would be needed by 2010, and 4,500 MW of new base load capacity would be needed by 2020. As a result, of the contributions from energy efficiency, cogeneration, demand response, and new renewable energy sources, this requirement is substantially less than the full replacement of OPG's current coal-fired generating capacity.[106]

Given that demand side efficiency policies take time to fully implement, and that the capacity to make a large investment in renewable energy sources such as wind power takes time to develop, this new base load capacity should be added on an as needed basis. However, this capacity need not exceed the 4,500 MW shortfall in total base load capacity otherwise projected by 2020.

A number of options are available to the province to meet remaining grid demand, including imports of electricity, new or refurbished nuclear generating facilities, "clean" coal, and combined cycle natural gas-fired generation. These options are discussed in the following sections.

5.4.1. Imports of Electricity from Other Jurisdictions

The Torrie Smith Associates study suggested reliance on imports of up to 3,000 MW during periods of peak demand from Manitoba and Quebec to address the

shortfall in Ontario generating capacity that may remain following the implementation of aggressive energy efficiency, cogeneration, and fuel switching initiatives.[107]

However, according to the IMO, the existing interconnection capacity between Ontario and neighbouring jurisdictions is 4,000 MW. Perhaps more importantly, the IMO estimates that only 1,400 MW of supply would likely be available for import during peak periods, as the available supply is largely from US jurisdictions subject to the same weather conditions as southern Ontario.[108]

The option of reliance on imports carries with it significant political, environmental, and social risks. The development of new large-scale hydro facilities in northern Manitoba, for example, would raise significant environmental concerns, and may also raise issues with First Nations in the region. Power losses from the long-distance transmission of electricity from northern Manitoba to markets in southern Ontario would be significant. Reliance on imports effectively externalizes the environmental and social costs associated with meeting Ontario's electricity demand onto other jurisdictions.

In the case of imports from the United States, Ontario is downwind of the coal-fired facilities in the US Midwest that would provide the bulk of the available supply. Reliance on these supplies would therefore defeat the air quality goals associated with the phase out of the province's existing coal-fired generating facilities.

All of these factors make reliance on imports to meet the province's electricity requirements an unattractive proposition, and one that should be reserved for use in emergency situations rather than meeting routine peaks in demand.

5.4.2. New or Refurbished Nuclear Generating Facilities

The refurbishment (principally the "retubing" of reactor cores) of OPG and Bruce Power's existing nuclear generating facilities to extend their projected lifetimes is an option under consideration by the province.[109] The Ontario Power Generation Review Committee, chaired by former federal Minister of Finance John Manley, recommended in its March 2004 report that OPG proceed with the refurbishment of Pickering Unit 1, and consider the refurbishment of the remaining units at Pickering "A" on the basis of the outcome of that effort.[110] Atomic Energy of Canada Ltd. (AECL), for its part, has raised the possibility of the construction of up to eight new 700 MW nuclear generating units to meet the province's future electricity needs, at a total cost of $12 billion.[111]

As noted by the province's Electricity Conservation and Supply Task Force, either nuclear option is associated with high and unpredictable capital costs.[112] In the case of new facilities, this problem is illustrated by the experience of the construction of the Darlington generating facility, whose costs rose from an original estimate of $3.95 billion in 1978 to a final actual cost of $14.4 billion.[113] The cost overruns associated with the efforts to bring the laid-up Pickering "A" units on line under the auspices of the Nuclear Asset Optimization Plan (NAOP)[114] highlight the same problems with refurbishment projects.[115]

AECL has suggested that price guarantees could be provided for the construction of new nuclear generating facilities.[116] However, such guarantees would ultimately depend upon the federal government's willingness to absorb any cost overruns. The federal government's willingness to do so has not been established. In addition, an attempt to site new nuclear generating facilities would likely prompt serious local resistance. New facilities would also require an extensive approval process through the Canadian Nuclear Safety Commission (CNSC) and federal and provincial environmental assessment legislation.

The Electricity Conservation and Supply Task Force suggested a minimum lead-time of seven years to bring new nuclear generation capacity on line for these reasons,[117] meaning that new supply would become available in 2011 at the earliest. Approvals involving technologies other than AECL CANDU-type reactors—those, therefore, unfamiliar to the CNSC—a possibility suggested by the OPG Review Committee,[118] would likely take even longer.

Estimates of the costs of refurbishing existing nuclear generating facilities in Ontario were developed for this study on the basis of past experience.[119] These estimates are presented in **Table 5.5**.

Table 5.5: Estimated Refurbishment Costs for Ontario Nuclear Generating Facilities (Current Dollars)

Station	Refurbishment Cost Range
Bruce 3 & 4	$720 million
Bruce 1 & 2	$1.5 to $2.5 billion
Pickering A	$3 to $4 billion
Pickering B	$3 to $4 billion
Bruce B	$3 to $4 billion
Darlington	$3 to $4 billion
Total	$14.2 to $19.2 billion
Midpoint	$16.7 billion

In addition to the up-front capital costs, it is unclear how long retubed reactors would be able to operate. Estimates, based on the performance of previously retubed reactors, range from eight to fourteen years.[120]

Reflecting the costs and uncertainties regarding retubing projects, in September 2002, the New Brunswick Public Utilities Board reached the following conclusion regarding a proposal by New Brunswick Power and AECL to refurbish the utility's Point Lepreau nuclear generating station:

> The Board, as a result of its review of the evidence in relation to the capacity factor and the cost of capital, finds that there is no significant economic advantage to the proposed refurbishment project. In addition, the Board considers that there are other significant aspects of the refurbishment option for which the economic impact is uncertain. These aspects create additional economic risk, which leads the Board to conclude that the refurbishment of Point Lepreau, as outlined in the evidence, is not in the public interest. The Board, therefore, will recommend to the Board of Directors of NB Power that it not proceed with the refurbishment of Point Lepreau. [121]

Beyond these concerns regarding capital costs and the length of time retubing would extend facility lifetimes, there are ongoing concerns regarding the overall reliability of nuclear generating facilities in Ontario. The annual capacity factor[122] for reactors in Ontario in 2003 was less than 50%.[123]

In addition to these immediate operational and reliability issues with respect to nuclear generation, there are ongoing concerns regarding safety in relation to major accidents, the health impacts of low-level releases of radioactive material from nuclear generating facilities, the unresolved question of long-term waste management,[124] undermined decommissioning costs, and the environmental and social costs associated with the mining and production of nuclear fuel.[125]

The most recent available production cost figure for nuclear energy in Ontario is 7.7 cents/kWh.[126] However, this figure likely underestimates long-term waste management costs, decommissioning costs, and does not include the costs of direct and indirect subsidies, such as those provided through the *Nuclear Liability Act*, and environmental and social externalities associated with nuclear fuel production.

This combination of factors makes the options of either the refurbishment of the province's existing nuclear generating facilities or the construction of new facilities an extremely high-cost and high-risk energy supply option for Ontario.

5.4.3. "Clean" Coal

The Pembina Institute examined a range of "clean" coal technologies in detail as part of its work on proposals for additional coal-fired generation in Alberta in 2001.[127] The technologies reviewed included subcritical and supercritical pulverized coal combustion (PCC), atmospheric pressurized fluidized bed combustion (AFBC and PFCB), and integrated gasification combined cycle (IGCC).

The only "clean coal" option found to have the potential to meet the Ontario government's air quality goals related to the phase-out of OPG's existing coal-fired plants is IGCC.[128]

In IGCC plants, coal is not burned in a traditional boiler but is converted into hydrocarbon vapour (syngas) in a gasifier. The syngas is then cleaned, stripped of impurities, and used as fuel instead of natural gas in a conventional combined cycle plant. The result is high system efficiencies and emissions of smog precursors and heavy metals comparable to combined cycle natural gas facilities. IGCC plants are operating commercially in the United States and have demonstrated high levels of reliability.[129]

The capital costs of IGCC are higher than other coal or natural gas-fired options. However, the operating costs of IGCC are relatively low, which means its overall levelized cost to produce electricity is comparable to that of combined cycle natural gas facilities.[130]

The use of coal as the source of fuel in these plants addresses the gas supply issues associated with natural gas-fired plants. However, the greenhouse gas emissions associated with IGCC plants are only 25% lower than those of conventional coal-fired facilities. This present a weakness in terms of the achievement of the province's air quality goals associated with the coal phase-out, and the fulfillment of Canada's wider greenhouse gas emission reduction obligations under the Kyoto Protocol.

5.4.4. Combined Cycle Natural Gas-Fired Generation (CCNG)

Commercial grade natural gas burns more cleanly than other fossil fuels as it consists mostly of methane and has already been cleaned of sulphur. In combined cycle natural gas-fired generation (CCNG) plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the host exhaust gas from the turbine is then used to generate steam in a waste heat recovery

unit. The steam is then used to produce more electricity in a steam turbine generator system. The output from both the gas turbine and the steam turbine electricity systems is combined to produce electricity very efficiently.[131]

CCNG plants produce low emissions of smog precursors, 60% of the greenhouse gas emissions associated with coal-fired options, and virtually no emissions of heavy metals.[132]

While natural gas is a much cleaner fuel than coal and makes an ideal bridging fuel to a sustainable future, it is not inexhaustible. The provision of the equivalent of 25,000 GWh of electricity through combined cycle natural gas-fired generation would increase the province's annual natural gas requirements by approximately 176 PJ.[133] In combination with the impact of the energy efficiency, cogeneration, and fuel switching measures outlined in section 3, this would increase total natural gas consumption by 2020 against current levels as outlined in **Table 5.6**.

Natural gas consumption at the projected 2020 level may exceed current pipeline capacity from western Canada.[134] However, the capacity of the TransCanada and Alliance/Vector pipeline systems may be increased substantially through the installation of additional compressors and by looping sections.[135] This would not require the construction of a new pipeline from western Canada.

Questions have been raised regarding the availability of long-term gas supplies to meet the additional demand flowing from the impact of increased reliance on CCNG for base load power supply in Ontario, particularly as production from conventional supplies in Alberta begin to decline.[136]

A 2001 study by the Canadian Gas Potential Committee suggested a 40-year supply of gas is available at 1998 production levels (233 Tcf) mostly in the Western Canadian Sedimentary Basin (WCSB) and Mackenzie Valley. This estimate did not include coal bed methane, estimated at an additional 74 Tcf in the WCSB.[137] The National Energy Board has suggested that the WCSB gas resource potential is 30 to 38 times greater than total production in 2001.[138] Total reserves have been estimated to be 68 to 76 times 2001 production on this basis.[139]

Concerns have also been raised with respect to the impact on electricity costs of natural gas prices in both the short and long term if the province becomes heavily reliant on gas-fired generation.[140] Natural gas prices can be subject to short-term peaks. This has been particularly true over the past few years in North America. These price shifts have been due to the limited ability of consumers to reduce their consumption in the short term, and of suppliers to increase short-term supply in situations where demand is high. Although medium and long-term projections for gas prices vary, they tend to forecast natural gas prices that are below current price levels.[141] The findings of a study on future Alberta natural gas prices completed for the Alberta Clean Air Strategic Alliance (CASA) are presented below.[142]

Table 5.6: Forecast Natural Gas Consumption (PJ), 2001 vs. 2020

2001 Total Consumption	842
CIMS Forecast of Increased Consumption in High Efficiency, High Cogeneration Scenario by 2020	370
CCNG Base Load Fuel Requirement, 2020	176
2020 Total Consumption	1,388

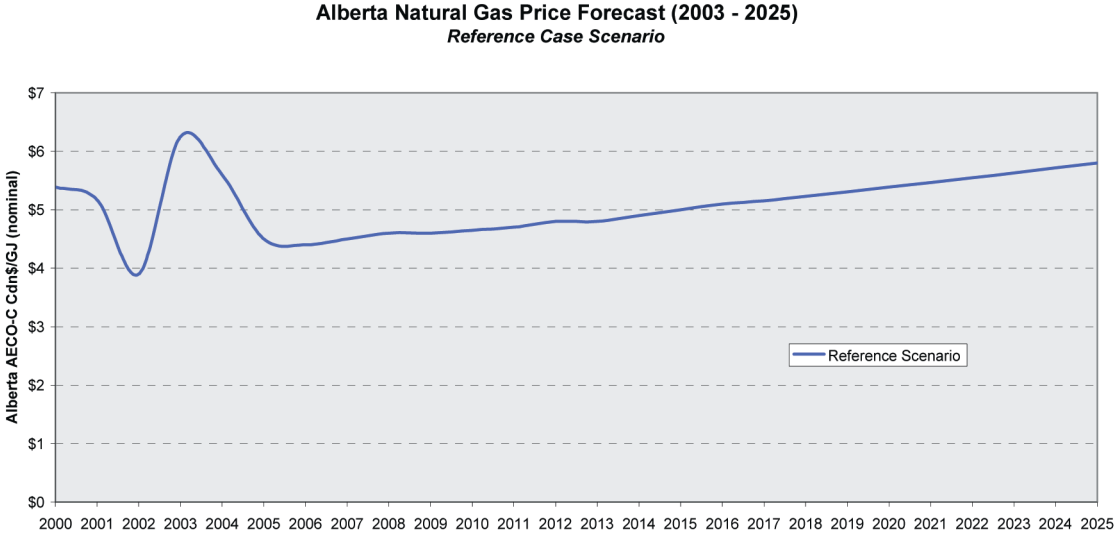


Figure 5.3: Alberta Natural Gas Price Forecast, 2000–2025 (Developed for CASA)

5.5. Supply Options Summary and Conclusions

The supply options available to meet the remaining base load requirements need to be assessed in light of the sustainability criteria outlined in section 2, as well as the costs for electricity delivered to consumers, their capital costs, and, in light of the province's emerging short-term electricity needs, the time within which they can be approved and brought into service.

Table 5.7 compares the electricity costs of the demand reduction and supply options examined in this study.

Table 5.7: Electricity Costs of Demand Reduction and Supply Options

Energy Efficiency Options	0–7 cents/kWh [143]
Cogeneration	3–5 cents/kWh [144]
Wind	8–10 cents/kWh [145]
Hydro	Heritage: 1.098 cents/kWh [146] New: 6–8 cents/kWh [147]
Biomass	6–9 cents/kWh [148]
Combined Cycle Natural Gas	5.18 cents/kWh [149]
Nuclear	7.8 cents/kWh [150]
Coal Integrated Gasification Combined Cycle	4.6–5.1 cents/kWh [151]

Table 5.8 provides estimates of the capital costs of different supply options.

Table 5.8: Estimated Capital Costs of Supply Options

Energy Efficiency Options	$1.36 million/MW [152]
Cogeneration	Not available but likely comparable to CCNG [153]
Wind	$1.5 million/MW [154]
Hydro	Not available. Depends on site and nature of project
Biomass	Not available but likely comparable to CCNG
Combined Cycle Natural Gas (CCNG)	$1 million/MW [155]
Nuclear	Refurbished: $1.125 million to 1.52 million/MW [156] New: $2.1 million/MW [157]
Coal Integrated Gasification Combined Cycle	$1.8 million/MW [158]

Table 5.9 provides estimates of the amount of time needed to bring different supply options into service, considering approval and construction times.

Table 5.9: Estimated Time to Service of Supply Options

Energy Efficiency Options	Transition to higher efficiency technologies largely complete by 2010 [159]
Cogeneration	2 years [160]
Wind	6 months to 1 year following approvals [161]
Hydro	Niagara tunnel: 5 years New small scale: dependant on nature of project
Biomass	2 years [162]
Combined Cycle Natural Gas	2 years [163]
Nuclear	Refurbished: 3–6 years [164] New: minimum 7 years [165]
Coal Integrated Gasification Combined Cycle	2–3 years [166]

In terms of costs per kWh of electricity efficiency measures, combined cycle natural gas generation and integrated gasification combined cycle generation are the lowest cost electricity supply options available to Ontario. This reinforces the importance of an emphasis on conservation as the option of first choice in the province's overall electricity strategy.

All of the non-nuclear supply alternatives offer the advantages of relatively short and well-established construction times. New nuclear generating facilities would have the highest capital costs, even assuming that there are no cost overruns. Such overruns have always been a feature of nuclear construction in the past in Ontario. Refurbished nuclear generating facilities would have higher construction costs than CCNG, and also carry with them a high degree of uncertainty. The uncertainty regarding the likely lifetime and reliability of refurbished reactors has to be taken into account as well.

Integrated gasification and combined cycle natural gas generation both offer the advantages of being well-established technologies with known capital costs, construction timelines, and high reliability. However, IGCC does not fully address the need to reduce the greenhouse gas emissions associated with electricity generation. At the same time, increases in gas consumption flowing from the replacement of electric heat with natural gas and significant increase in cogeneration outlined in Table 5.6 imply that natural gas should be used sparingly as a supply source and as efficiently as possible. In addition, CCNG is subject to short-term cost concerns due to the potential short-term volatility of natural gas prices, although this may be mitigated through long-term supply contracts with fixed prices. All of these factors suggest a role for CCNG as an option once efficiency and sustainable supply options have been maximized.

It is important to consider the costs associated with nuclear generation that are not accounted for in the figure in Table 5.7. These include such things as decommissioning, long-term waste management, servicing offloaded stranded debt associated with construction and refurbishment of nuclear generating facilities, and the environmental and social externalities associated with the production of nuclear fuel. This implies that the figure in Table 5.7, provided by OPG, significantly underestimates the actual cost of nuclear generation.

In addition, the high externalized environmental and social costs of the production of nuclear fuel relative to the very low externalities of new renewable energy sources [167] must be considered. There are also security and safety risks associated with nuclear generating facilities that are low or virtually non-existent with renewable energy sources. The improved reliability, lower system risks, and avoided grid upgrading costs from distributed generation from multiple technologies relative to a centralized generation system reliant on single technology must be factored in as well.

In the context of these considerations, the preferred approach to meeting remaining grid demand, having maximized contributions from energy efficiency, cogeneration, fuel switching, and demand response measures, is to maximize the contribution from low-impact renewable energy sources. On the basis of cost, reliability, safety, security, and lowest environmental impact, combined cycle natural gas generation should be used to meet the remaining base load demand.

The final proposed supply mix is presented in **Table 5.10**.

Table 5.10: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

6. Conclusions and Recommendations

This study was undertaken in the context of growing concern over the future direction of Ontario's electricity system. The combination of the projected end of life of the province's existing coal-fired and nuclear generating stations, and predictions of growing electricity demand have prompted a major debate over the province's future electricity needs, and how those needs might be met.

In this context, this study sought to answer four key questions regarding future electricity supply and demand in Ontario:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

6.1. Energy Efficiency Potential and Remaining Grid Demand

The first question was explored in sections 3 and 4 of the study. The study concludes that through the combination of a number of policies intended to prompt the adoption of energy efficient technologies, industrial and commercial/institutional sector cogeneration, fuel switching from electricity to natural gas, and demand response measures, total grid demand could be reduced against business-as-usual projections as shown in **Table 4.1**, reproduced below.

Table 4.1: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	**Summer**	**Winter**	**Summer**	**Winter**	**Summer**
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

As Table 4.1 shows, net summer peak demand could be reduced by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

The study finds that capital investments of $18.2 billion over the 2005–2020 period would be required to achieve these savings through energy efficiency, fuel switching, and cogeneration. However, 96% of these costs would be recovered by consumers through their savings in energy consumption resulting from these investments. Ontario's natural gas consumption would increase by 12% over business-as-usual projections by 2020 as a result of the energy efficient technological and behavioural changes flowing from these measures.

6.2. Meeting Remaining Grid Demand

The second and third questions were explored in section 5 of the study. The analysis presented there concluded that it would be reasonable to expect that the contributions to Ontario's electricity supply from new hydro, wind, and biomass by 2020 could be as shown in **Table 6.1**.

Table 6.1: Potential Renewable Energy Supply, 2010–2020

	2010			2015			2020		
Source	**GWh**	**Peak (MW)**	**Capacity (MW)**	**GWh**	**Peak (MW)**	**Capacity (MW)**	**GWh**	**Peak (MW)**	**Capacity (MW)**
Wind	7,884	1,317	3,000	12,208	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4205	281	600	5,606	375	800
TOTAL	15,768	2,151	4,500	22,983	3,377	7,100	32,762	4,649	9,800

As shown in Table 5.4 the province will also require 4,500 MW of new base load generating capacity to meet the balance of the province's electricity needs by 2020. This table assumes that the province maximizes the technologically and economically feasible contributions from energy efficiency measures and low-impact renewable energy sources. The projected date for the phase-out of the province's coal-fired generating facilities is no later than 2010, and the projected end of the operating lives of the province's existing nuclear generating facilities is 2018.

The study concludes that on the basis of costs, environmental and health impacts, speed of construction, and reliability, the remaining base load requirement would be best met through combined cycle natural gas generating facilities. However, in light of the concern in the very long term regarding natural gas supplies in North America, these facilities should be seen as an interim measure towards a system that relies on more advanced renewable energy sources in the future.

The final estimated grid demand and proposed supply mix was outlined in **Table 5.10**, reproduced on the next page.

Table 5.10: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

It is important to compare the financial, economic, and social implications of the supply options available to the province to meet its future electricity needs. Under the business-as-usual scenario, assuming that existing hydro and peaking gas and replaced oil-fired generating capacity are retained, demand response programs are pursued, and that renewable energy sources are maximized as suggested by the Electricity Conservation and Supply Task Force, but aggressive efficiency programs and new combined cycle natural gas baseload supply are not pursued, a peak supply gap of nearly 15,000MW[168] would emerge by 2020. Meeting this gap through new nuclear generation would carry a capital cost of over $39 billion.[169]

The capital costs of addressing the same gap through a combination of energy efficiency measures, fuel switching, cogeneration, and new combined cycle natural gas generation as outlined in this study, by comparison, would be in the range of $23 billion.[170] In addition to these avoided capital costs, a supply strategy focused on improving energy efficiency rather than creating new generation would carry with it other benefits: the avoided costs of producing the electricity and gas saved as a result of energy efficiency measures, and the environmental, health, safety, and security co-benefits associated with avoiding the need to construct and operate new generating capacity that would be required under business-as-usual scenarios. There would also be overall improvements in housing quality and the competitiveness of Ontario industry as a result of investments in more modern and energy efficient technologies.

6.3. Implementing a Sustainable Electricity System

6.3.1. Maximizing the Efficient Use of Electricity

Achieving the potential reduction in electricity demand identified in this study by 2020 will not be easy or without risk. However, other jurisdictions in North America are implementing the types of program that will be needed in Ontario to achieve this target.[171] With the appropriate regulatory foundation in the form of minimum energy efficiency standards and labelling, the Ontario Energy Board (OEB) incentive mechanisms for utilities, and improved grid access for cogenerators, major reductions in electricity consumption can be achieved without excessive costs to government or energy consumers, or by penalizing low-income members of Ontario society.

This section begins with a series of foundation policies that would be needed for an energy efficiency strategy to succeed. This is followed by a discussion of provincial energy efficiency programs to supplement the foundation measures. Finally, the questions of the coordination and management of an efficiency strategy and cost sharing are discussed.

6.3.1.1. Foundation Policies

Minimum Energy Efficiency Standards

The CIMS results show that a combination of financial incentives and innovative financing could transform the market for new and replacement energy efficient technologies and fuel switching by 2010. Policies to remove the barriers to cogeneration would also produce a rapid uptake of this option in the industrial and commercial/institutional sectors. If this market transformation could be maintained, the CIMS results show that simple stock turnover could be used to reduce electricity consumption in Ontario to 121,000 GWh/yr by 2010 and 107,000 GWh/yr by 2020.

The simplest and lowest administrative cost way of ensuring that the transformation continues is to raise minimum energy efficiency standards for electricity-using products and energy codes for buildings to the energy efficiency levels of the CIMS targeted technologies. Once a significant market transformation has occurred, this could be done without disruption of these markets.

California, for example, has reduced peak power demand by 20%, or 10,000 MW, over the past 20 years, with a combination of utility demand side management programs, and building and appliance standards. [172]

Recommendation 1: The Government of Ontario should adopt minimum energy efficiency standards under the **Energy Efficiency Act** equivalent to the energy efficiency levels required for Energy Star labelling for all major electricity-using devices and equipment when the market share for new or replacement energy efficient models surpasses 50%, and not later than 2010 for all devices. The province should develop its own energy] efficiency standards for equipment not covered by Energy Star.

Recommendation 2: The provincial Building Code should be amended to require R2000, Canadian Building Improvement Program (CBIP), or equivalent energy efficiency performance for all new buildings and building renovations by 2010.

Recommendation 3: The **Planning Act** should be amended to permit municipalities to make energy efficiency design requirements a condition of site approvals for buildings.

Labelling of Energy Efficient Products

The United States Environmental Protection Agency's Energy Star program, which provides for the labelling of products with the highest energy efficiency, is now used internationally to identify efficient lighting, appliances, computers, motors, and many other products. It has recently been introduced into Canada and has been successfully used in Ontario as the basis for its energy efficient appliance sales tax rebate program. As part of BC Hydro's Power Smart programs, Energy Star labelling increased the market share of efficient appliances by several percentage points. [173]

Recommendation 4: The most energy efficient technologies in all sectors and end-uses should be labelled through the Energy Star program or, if not included in Energy Star, through a provincial labelling system.

Utility Regulation and Demand Side Management Incentive Mechanisms

In order to develop and maintain a culture of energy efficiency in Ontario, the benefits of efficiency need to be embedded within the utility regulatory system. It must always be financially beneficial for electrical distribution utilities to undertake demand side management (DSM) programs. Without this being made a permanent feature of the utility regulatory system, energy consumers will not have the stable environment necessary to make the required efficient investments.

The current shared savings DSM incentive mechanisms applied to Enbridge Gas Distribution in Ontario have been successful in creating an energy efficient culture within the utility, where efficiency targets are set and DSM programs are delivered on an ongoing basis. The utility shares in the financial savings from the DSM programs through incentive mechanisms.[174]

Extending this concept to Ontario's electricity distribution utilities will present challenges. However, a significant reduction in energy demand has been achieved through DSM programs encouraged by government incentive structures in California.[175]

Utilities could also be allowed to meet energy efficiency targets by contracting among themselves or to energy service companies to deliver DSM programs. All utilities could be regulated in this fashion, even if they do not have the internal expertise in DSM.

The small size of some distribution utilities should not prevent them from being included in the DSM incentive mechanisms. Aquila Networks, a small electric utility serving the Kootenay and Okanagan regions of British Columbia, for example, has successfully used a DSM incentive mechanism for nearly 10 years under a performance-based rate setting regime regulated by the BC Utilities Commission.[176]

While a DSM incentive mechanism for electrical utilities in Ontario will not in itself be sufficient to bring about the energy efficiency improvements shown to be possible in the CIMS analysis, it is an essential requirement if other efficiency measures are to succeed. Utilities must be major, permanent partners in improving energy efficiency, and offer DSM programs over the long term. Without an incentive mechanism, utilities benefit from higher electricity sales, and therefore have strong incentives not to pursue DSM activities.

> **Recommendation 5:** The OEB performance-based rate setting and DSM incentive mechanism model currently applied to Enbridge Gas Distribution should be extended to Hydro One and all of Ontario's electrical distribution utilities. All distribution utilities should be required to set targets for energy efficiency gains and be allowed to then share in the benefits of DSM programs. The incentive mechanisms should allow utilities without DSM capabilities to meet their targets by contracting the delivery of DSM programs to other electrical and gas utilities, the energy service industry, or specialized non-profit agencies.

Improved Grid Access for Cogenerators

In order to make it worthwhile for industrial and commercial/institutional facilities to increase their cogeneration of heat and power and to sell the excess power to the grid, a regime needs to be put in place that both makes it financially worthwhile and technically simple177 for them to do so.

The key measure needed to encourage more cogeneration and renewable energy on-site power generation is net metering—effectively paying the same price for power produced as for power used. In addition, practical and safe specifications for power quality, metering, switching, inverters, and other technical matters are needed for grid inter-ties. Inspectors, meter readers, and other utility staff need to be provided with information and training on the integration of local power sources. These specifications should reflect an assumption that local power sources are commonplace rather than the exception.

Grid inter-ties and net metering should also be designed such that power supplied to the grid is measured separately from the amount taken from the grid.[178] This would allow policies to be implemented where higher prices are paid for excess power supplied to the grid than the purchase price. Special requests for proposals (RFPs) or feed-in tariffs[179] could be used to encourage industries and large commercial and institutional users to develop cogeneration potential.

> **Recommendation 6:** The Government of Ontario should expand its current net metering policy to include all industrial, commercial/institutional, and residential users, and develop grid inter-tie specifications and training programs for utility staff. A series of annual special RFPs or feed-in tariffs should be issued to encourage smaller industries and large commercial and institutional facilities to develop their cogeneration potential.

6.3.1.2. Provincial Energy Efficiency Programs

In addition to the adoption of these foundational policies, the Government of Ontario should implement a series of energy efficiency programs that would accelerate the transition to energy efficient products and technologies and increase the market share of energy efficient technologies to a level where minimum energy efficiency standards and codes can be raised without significant adverse economic impacts.

A Partnership to Deliver Innovative Financing Programs

The individual CIMS runs showed that lowering of user-perceived discount rates[180] had the largest impact

on electricity consumption, followed by cogeneration and financial incentives to reduce the up-front capital costs of more energy efficient equipment. The most effective way of reducing the perceived discount rate is through financing mechanisms that allow electricity consumers in all sectors to finance the higher cost of energy efficient technologies out of the savings obtained as these savings occur.

The province should form partnerships with electric and gas utilities, energy service companies, and financial institutions to provide a suite of programs to provide financing for energy efficient technologies and measures. One example is the Better Buildings Partnership model conceived in Toronto that uses a revolving fund to finance energy efficiency improvements in buildings managed by energy service companies.[181] Another example of a model for financing the purchase of higher efficiency energy using products is the SaskEnergy prime rate financing for Energy Star furnaces.[182] Given the longer payback for permanent energy efficiency improvements to buildings, innovative new financing approaches such as using local improvement charges to pay back the cost of retrofits—attaching the cost and benefits to the building property instead of the owner—are being developed.[183] Many of the programs could be delivered by distribution utilities under a DSM incentive mechanism.

Recommendation 7: The Government of Ontario should establish a partnership with utilities, financial institutions, energy service companies, municipalities, and other stakeholders to offer a series of financing mechanisms to assist electricity consumers in all sectors to finance the adoption of energy efficient products and technologies and measures out of the savings they will achieve through these investments.

Financial Incentives

The CIMS results showed that on their own, financial incentives that reduce the first cost of energy efficient technologies would have only a modest impact on the adoption of more energy efficient technologies. However, a small financial incentive increases the likelihood of a consumer taking advantage of a financing program, particularly in the early stages of a program, when an energy efficient product may be less available and more expensive. Incentives like the current Ontario sales tax removal for Energy Star appliances and the federal grants for home energy retrofits would have the "pump priming" effect needed to start market transformation. Through the Office of Energy Efficiency, the federal government is offering grants to support making new and existing commercial buildings[184] more energy efficient.

The Government of Ontario should pursue an agreement with the federal government to share the costs of an expanded sales tax rebate system and extend similar incentives to a set of priority energy end-uses not covered by federal incentives, particularly lighting, hot water heating, industrial drive power, and household appliances. This could be done under a federal-provincial agreement to reduce Ontario's greenhouse gas emissions as part of Canada's Kyoto Protocol commitments.

However, incentive programs should only be kept in place for a period of five years. After that point, other policies and programs should start to consolidate the market transformation, and minimum energy efficiency standards could be put in place to complete the process.

Recommendation 8: The Government of Ontario should enter into an agreement with the federal government under the auspices of the federal government's Kyoto Protocol implementation plan to share the costs of providing the following financial incentives for the adoption of energy efficient technologies:

- Grants for high efficiency home energy retrofits and new R2000 homes
- Grants towards the additional cost of new high-efficiency commercial buildings, and commercial building retrofits
- Sales tax rebates for all Energy Star products in all sectors and small-scale renewable energy power sources
- Business tax credits for industrial energy efficiency equipment and cogeneration systems.

These incentives should focus initially on technologies where the largest reductions can be achieved at the lowest cost, such as commercial HVAC and lighting, and industrial drive power. The incentives should be in effect only until the market share of the efficient technology reaches 50%.

Special Assistance for Low-Income Households

Even with innovative financing programs and financial incentives, higher energy efficient technologies are often beyond the reach of low-income consumers. They may rent their accommodation and appliances, or may lack access to the capital needed to buy new appliances. For those that do own homes, the needed

improvements may go well beyond energy efficiency upgrades. Low-income consumers therefore face the double problem of rising power prices and not being able to reduce their energy use. Several US states and countries like the UK have set up special programs to deliver energy efficiency programs to low-income housing, focusing on comprehensive building improvements and ways that make high-efficiency lighting, appliances, and heating systems more affordable.[185]

Recommendation 9: Mechanisms to ensure the delivery of programs to low-income consumers should be incorporated into the DSM mandates and incentives provided to energy and electrical distribution utilities. A specific portion of DSM spending should be set aside for this purpose, including revenues from the Public Benefits Charge proposed in Recommendation 11.

6.3.1.3. Provincial Leadership and Coordination of Energy Efficiency Programs

The foundation policies and programs outlined in Recommendations 1 to 9 would form the basis for an integrated 15-year strategy designed to reduce electricity demand in Ontario by 30% below 2003 levels by 2020. While responsibility for direct implementation of energy efficiency programs would be in the hands of electricity and natural gas distribution utilities' strong leadership, support and oversight would need to be provided by the provincial government.

The Minister of Energy has recently proposed the creation of an Ontario Power Authority with responsibility for carrying out planning functions and issuing calls for proposals to the private sector for new generation.[186] This approach runs a significant risk of placing an overwhelming and unnecessary emphasis on the construction of new supply, unless the authority is placed within a broader institutional structure that strongly emphasizes overall energy sustainability.

Recommendation 10: The Government of Ontario should adopt legislation creating a new agency, the Ontario Sustainable Energy Authority, reporting to the Minister of Energy, to lead and coordinate the province's energy efficiency and electricity planning efforts.[187]

The agency's functions should include:

- The coordination and oversight of the development and implementation of provincial energy efficiency standards and labelling programs
- Ensuring the consideration of energy efficiency in the policies and programs of provincial government agencies
- The ongoing assessment of the effectiveness of energy efficiency programs being delivered by utilities and provincial agencies, including low-income programs and the provision of recommendations for their improvement to the provincial government and the OEB
- The forecasting of the province's future electricity needs
- Research, development, education, and information dissemination on energy efficient technologies and practices

The proposed Ontario Power Authority, responsible for issuing requests for proposals for the construction of new generating capacity, should be a division of the new agency.

6.3.1.4. Costs and Cost Sharing

The bulk of the costs of DSM programs delivered by regulated utilities in Ontario could be recovered through the performance rate setting process and DSM incentive mechanism governed by the OEB.

However, the province would be faced with the costs of its share of the financial incentives outlined in Recommendation 8. A reasonable estimate of this cost, assuming that it reflects the removal of the provincial sales tax on energy efficient equipment and appliances, would be 8% of the investment in energy efficient technologies from 2005 to 2010. Under the federal-provincial Kyoto Protocol implementation agreement proposed in Recommendation 8, the federal government could be asked to contribute 50% of these costs.

In addition, there would be administrative costs associated with the development and implementation of minimum energy efficiency standards and labelling programs, and overall program coordination.

Many US states that have restructured their electrical utilities have introduced small public benefits charges (PBC) on each kWh of electricity sold to finance energy efficiency programs.[188] The use of the funds raised varies from state to state, but the basic objectives are to compensate for the fact that the new utility structure removes incentives for utilities to carry out DSM programs, and to make the financing of energy efficiency programs more revenue neutral.[189] Many US states[190] and the United Kingdom[191] have used PBCs to finance programs specifically targeted at helping low-income consumers improve the quality of their housing and adopt more efficient electricity-using appliances.

Recommendation 11: A PBC of 0.3 cents/kWh should be applied on all electricity sales to finance energy efficiency and low-income assistance programs.[192]

The PBC would be levied on all electricity sales and be revenue neutral in that it would go back to consumers who receive the financial incentives or to low-income consumers. Consumers who do not purchase targeted technologies, or take advantage of DSM programs offered by utilities, will lose their contribution to the PBC and also have to pay higher tariffs.[193]

Table 6.3 shows the revenues that could be generated through a PBC, and potential uses of these revenues.

Table 6.3: PBC Funding Distribution for Energy Efficiency Programs (5-Year Increments)

	2005–2010	2010–2015	2015–2020
Income from a 0.3 cent/kWh PBC Levied on All Power Sales[194]	$2,040 million	$1,755 million	$1,557 million
Cost of Incentives (8% of Targeted Technologies)	$627 million		
Assumed Ontario Share (50%)	$313 million		
Program Capitalization, Low-Income Program Delivery, Research and Development of Energy Efficiency and Renewable Energy Technologies, Program Administration, including Development and Administration of Standards and Labelling Programs	$1,727 million	$1,755 million	$1,557 million

The CIMS results show that the net cost (revenue) of the possible energy efficiency gains to Ontario consumers, assuming that all incremental costs are paid by electricity consumers, is shown in **Table 3.8** (reproduced from section 3).

Table 3.8: Forecast Incremental Costs Associated with Achieving 2020 Energy Savings (discounted to 2004)

Sector	Incremental Costs Associated with Achieving 2020 Savings In millions of dollars (discounted to 2004)			
	Investment	Operation and Maintenance	Energy	Total
Industrial	829	273	(1,255)	(153)
Residential	7,220	(45)	(6,174)	1,001
Commercial/Institutional*	10,211	1,345	(11,782)	(226)
TOTAL	18,260	1,573	(19,211)	622

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

Only the residential sector shows a net cost, and, as shown in section 3, this is equivalent to approximately $6 per person per year. This cost would be further reduced by the incentives paid during the first five years, and increased very slightly by the PBC.

6.3.1.5. Demand Response Measures

As outlined in section 4.1, it is estimated that peak electricity demand could be reduced by up to 10% through demand response measures.

Recommendation 12: The Government of Ontario should implement the following demand response policies:

- The OEB should be directed to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market.
- The Government of Ontario should assess the infrastructure needed to encourage and facilitate demand response in the Ontario market. A portion of the revenues generated by the PBC proposed in Recommendation 11 should be used to meet the costs of providing the required infrastructure.
- All electricity consumers should be able to participate in demand response programs, and should not be capped in terms of the level of their participation.[195]

In addition, the 1,000 MW solar roof program outlined in section 4.2 could provide a significant reduction in summer peak demand.

Recommendation 13: The Government of Ontario should undertake a design and costing study for a 200,000 unit solar PV roof program modelled on those undertaken in Europe and the United States, and implement this program using a feed-in tariff funding mechanism.

6.3.2. Achieving a Sustainable Supply Mix

Section 5 concluded that following the maximization of the potential contributions from energy efficiency, cogeneration, fuel switching, and demand response measures, the province should seek to maximize the contributions from low-impact renewable energy sources. These include the upgrading of existing hydro facilities, the development of new small-scale hydro plants, large scale wind generation, and the use of landfill, sewage, and anaerobic waste digestion gas capture and generation.

A number of steps are needed to ensure that the potential contributions from these sources are maximized.

6.3.2.1. Renewable Portfolio Standard/Requests for Proposals

The Ontario Wind Power Task Force has highlighted the point that renewable energy sources suffer price disadvantages relative to conventional energy sources, due to the unaccounted externalized environmental and health costs of fossil fuels.[196] Renewable energy sources may also face barriers in entering markets in which conventional energy suppliers are well established. Although further reductions in the costs of wind power generation technology are expected in the future, many jurisdictions in the United States and Europe have adopted mechanisms to accelerate the development of renewable energy sources, particularly through the adoption of renewable portfolio standards (RPS) for renewable energy sources.[197]

An RPS effectively guarantees a portion of the electricity market to renewable energy sources, either through direct calls for a certain amount of supply, or by requiring that all RFPs for new supply include a certain portion from renewable energy sources. This has the effect of enabling potential renewable energy suppliers to obtain financing to develop their projects, by ensuring that there will be a market for their energy if they proceed with development.

In Ontario, an RPS would need to be sufficiently large to signal that demand for equipment, especially wind power generation technologies, will be high enough to justify the establishment of a manufacturing industry in Canada. The development of such an industry would carry with it significant employment benefits, and also reduce the industry's vulnerability to changes in capital costs due to shifts in foreign exchange rates affecting equipment prices.

The RFPs should be competitive, and decisions should be based on price, certainty of delivery, and reliability.

Recommendation 14: The Government of Ontario should issue, through the IMO, RFPs for supply from wind, upgraded existing or new small scale hydro, solar, the use of waste-generated methane from municipal, agricultural, industrial sources and other low-impact renewable energy sources. The initial RFPs should seek to have 4,500 MW capacity in place by 2010, followed by additional calls for supply up to 7,100 MW by 2015 and 9,800 MW by 2020.

6.3.2.2. Renewable Energy Potential Assessment

Section 5 of this study highlighted the poor state of the available estimates of the potential contributions to the province's electricity supply from renewable energy sources. These are incomplete, often out of date, and do not reflect current technologies. Experience in other jurisdictions, such as Germany, confirm that contributions on the scale of Ontario's existing conventional sources of supply, such as coal, are possible.[198] However, much more precise estimates of the potential contributions from renewable energy sources are needed to facilitate long-term planning and policy development.

Recommendation 15: The Government of Ontario should undertake, on an urgent basis, a complete up-to-date assessment of the potential contributions from onshore and offshore wind generation, small scale hydro, and the use of waste digestion-generated methane, to the province's future energy supply. This effort should include primary research as required, including detailed wind potential mapping.

Recommendation 16: The Government of Ontario should initiate a research and development program on renewable energy technologies funded through the PBC proposed in Recommendation 11. This should include both technology development and the resolution of grid integration issues.

6.3.2.3. System Integration Improvements for Renewable Energy

Some renewable energy sources have limited dispatch capability (e.g. run-of river hydro). Other sources, such as wind, are intermittent, but match peaks in demand quite well. Hydro with storage capacity can be used for both base load and peaking, although it can be associated with higher environmental impacts. Electronic control and power regulation equipment and accurate weather forecasting can allow grid dispatchers to forecast power outputs from renewable energy sources such as solar, wind, and run-of-river hydro, and dispatch hydro storage and natural gas peaking facilities as needed, allowing the potential contributions from renewable energy sources to be maximized.

Recommendation 17: The IMO should adopt management practices designed to forecast power outputs from wind power capacity and run-of-river hydro (and solar PV systems), and be prepared to dispatch hydro storage and existing natural gas facilities as needed to provide base load capacity.

6.2.3.4. Resolution of Land-Use Planning and Site Approval Issues for Low-Impact Renewable Energy Sources

Siting conflicts are emerging as a significant barrier to the establishment of new renewable energy generating capacity, particularly with respect to wind installations. In response, some elements of the wind industry have pressed for exemptions from land-use planning and environmental assessment requirements for wind power generating facilities. [199]

This may not be the best approach to these issues, and may actually have the effect of exacerbating local land-use conflicts over new renewable energy generating facilities. A better strategy may be to develop land-use guidelines and policies related to renewable energy sources, particularly wind, with a range of affected constituencies. This strategy may place some attractive locations associated with important natural heritage or biodiversity functions off-limits to development, but will ease the industry's development more generally in the long term.

Recommendation 18: The Government of Ontario should establish and expedite the completion of a consultative process to develop land-use guidelines for the siting of renewable energy generating facilities.

Offshore wind power generation technology is well developed and in widespread use in Europe. Offshore installations would avoid many of the land-use conflicts that have been associated with land-based facilities. Federal approvals may be needed under the *Fisheries Act* and the *Navigable Waters Protection Act* for offshore facilities.

Recommendation 19: The Government of Ontario should develop guidelines, in conjunction with the federal government, for the approval of offshore wind power generation facilities.

6.3.2.5. Long-term Supply Contracts for Required Base Load

A number of supply options were examined in section 5.4 of this study to meet the remaining 4,500 MW of

base load generating capacity that this study projects that the province would need by 2020, even with the maximization of energy efficiency, and the contributions from renewable energy sources.

These supply options included imports of electricity from other provinces, new or refurbished nuclear generating facilities, "clean" coal technologies, and combined cycle natural gas fired generation. On the basis of considerations of cost, safety, security, reliability, construction time and environmental and health impacts, the study concluded that the best option to meet this base load need is new combined cycle natural gas generating facilities.

The RFPs for new base load supply should be competitive, and decisions should be based on price, ability to meet environmental, health, safety, reliability criteria, and certainty of delivery and timeliness of development.

Recommendation 20: The Government of Ontario should issue, through the IMO, a request for proposals for long-term base load supply, meeting the construction time, cost, reliability, and environmental, health, and safety performance of combined cycle natural gas generating facilities.
The call for proposals should seek to have 4,200 MW of new base load supply in place by 2007 and 4,500 MW in place by 2020.

6.4. Implementation Plan

An overall implementation plan for the elements embodied in Recommendations 1 to 20 is presented in **Table 6.4**.

6.5. Conclusions

Ontario is now at a critical juncture in terms of its future energy path. The decisions made about electricity policy over the next year will set the province's course for the next 20 or 30 years. The choices the province makes will have major implications for the health, environment, safety, and security of Ontario residents, and the competitiveness of Ontario's businesses and industries for decades to come.

This study has shown that the choice faced by the province is clear. The province can take the path of making a massive investment in a generation technology, namely nuclear power, that has never lived up to its promise, is in large measure responsible for the environmental, reliability, and financial crises now facing Ontario's electricity system, and which carries with it enormous environmental and economic risks and costs to present and future generations of Ontarians.

In the alternative, the province can choose the path, as laid out in this study, of setting a policy framework that will result in the widespread adoption of proven energy efficient technologies and practices that will reduce consumers' energy bills, improve air quality, protect the health and safety of Ontario residents, and result in a more, safe, secure, and reliable electricity system.

The decision on what path to take now rests with the current Government of Ontario. The health, safety, and well being of future generations of Ontario residents rests on whether it chooses wisely.

Table 6.4: Implementation Plan for Recommendations

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nuclear Facility End of Life																	
Coal Facility Phase-Out																	
Minimum Efficiency Standards and Building Code Revisions Development and Adoption																	
Labelling Program Development and Implementation																	
Utility DSM Incentive Mechanisms in Place																	
Net Metering and Grid Access Implementation																	
Energy Efficiency Partnership Financing Mechanisms Established																	
Financial Incentive Implementation																	
Low-Income Household Assistance																	
Provincial Coordinating Agency Establishment																	
PBC Implementation																	
Demand Response Implementation																	
Solar Roofs Program Design and Implementation																	
Renewable Energy Potential Assessment																	
Renewable RPS Implementation: Phase 1																	
Phase 2																	
Phase 3																	
Renewable Energy Dispatch Management Mechanism Implementation																	
Renewable Energy Onshore and Offshore Siting Guidelines Development																	
New Base Load RFPs and Construction																	

Endnotes

1 On the creation of the HEPC see N. B. Freeman, *The Politics of Power: Ontario Hydro and Its Government 1906–1995* (Toronto: University of Toronto Press, 1996), Chapter 2.

2 See Freeman, *The Politics of Power*, Chapter 6, on the establishment of Ontario Hydro.

3 Ontario Hydro's total debt at the time of the coming into force of the legislation was $38 billion.

4 On the Electrical Safety Authority, see M. Winfield and H. Benefides, "Drinking Water Protection in Ontario: A Comparison of Direct and Alternative Service Delivery Options" (Ottawa: The Pembina Institute, 2001), Appendix 4.

5 The design of the new system flowed from the 1996 report of the Advisory Committee on Competition in Ontario's Electricity System. See Advisory Committee on Competition in Ontario's Electricity System, " A Framework for Competition" (Toronto: Queen's Printer for Ontario, 1996).

6 This was to be achieved through a "Market Power Mitigation Agreement," negotiated between OPG and the provincial government. See Market Design Committee, "Third Interim Report" (October 8, 1998), 1–5.

7 Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: January 2004), Figure 3.A. Under the market system, the hourly electricity price was determined on the basis of the price of the last amount dispatched into the market (i.e., the "spot" market price).

8 Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: January 2004), Figure 3.A.

9 The Hon. D. Duncan, Minister of Energy, Notes for Remarks to the Canadian Energy Efficiency Alliance, February 17, 2004.

10 See R. Mackie, "McGuinty government raises price cap on hydro," *Globe and Mail*, November 26, 2003.

11 See Government of Ontario, "Eves Government Takes Action to Promote Green Energy, Alternative Fuels and Conservation" (news release, November 13, 2002).

12 Ministry of Energy, "Ernie Eves Government Introduces Standard to Increase Green Energy," (news release, July 3, 2003).

13 Ontario Hydro, "Report to Management IIPA/SSFI Evaluation Findings and Recommendations" (Toronto: Ontario Hydro, July 1997).

14 This refers to four units at Pickering "A" and three units at Bruce "A"; Bruce Unit 2 had been shut down in October 1995.

15 Ontario Hydro, "Ontario Hydro Moving Ahead on Major Overhaul of Production Facilities" (news release, August 13, 1997).

16 J. Gibbons, "Countdown Coal: How Ontario can improve air quality by phasing out coal-fired electricity generation" (Toronto: Ontario Clean Air Alliance, February 2003), Appendix C.

17 Ontario Clean Air Alliance, "Countdown Coal" 2.

18 See, for example, Toronto Public Health, "Air Pollution Burden of Illness in Toronto: Summary Report" (Toronto: City of Toronto, May 2000).

19 See Pickering Review Panel, "Report of the Pickering 'A' Review Panel" (Toronto: Ministry of Energy, December 2003), 3. The estimates available to the panel for the return to service of the remaining three units were $3–$4 billion, with return to service between October 2006 and August 2008.

20 "Bruce unit 3 resumes electricity production" *Toronto Star*, January 10, 2004. The Bruce "A" and "B" facilities were leased to British Energy in May 2001. Following the bankruptcy of British Energy, the lease was transferred to Bruce Power Inc., a consortium of Cameco, TransCanada Pipelines, OMERS, the Power Workers Union, and the Society of Energy Professionals.

21 See Appendix 2 "Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs" for a detailed discussion of the refurbishment of the Bruce "A" units.

22 Imports accounted for 3% of supply in 1997 and 7% in 2003. Maximum current import capacity for Ontario is 4,000 MW. The IMO estimates that the maximum amount of power available for import during peak months is 1,400 MW. See IMO, "18 Month Outlook: An Assessment of the Reliability of the Ontario Electricity System from July 2003 to December 2004" (Toronto: IMO, June 2003).

23 IMO, "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2004 to December 2012" (Toronto: IMO, March 2003).

24 See Freeman, *The Politics of Power*, 171–179.

25 See M. Winfield and G. Jenish, "Ontario's Environment and the 'Common Sense Revolution': A Four Year Report" (Toronto: Canadian Institute for Environmental Law and Policy, 1999), 3–47.

26 Ministry of Energy, "Energy Minister Announces Plan to Address First Third of Coal Commitment," (news release, January 20, 2004). The retirement dates for the coal-fired facilities without the coal phase-out would be as follows: Nanticoke 2015; Lambton 2010–2020; Thunder Bay 2021; Atikokan 2025. (pers. comm., Jack Gibbons, Ontario Clean Air Alliance, November 18, 2003, [based on OPG information]).

27 See Ministry of Energy, "Ontario Government Takes Responsible Action On Electricity Pricing," (news release, November 25, 2003); R. Mackie, "McGuinty government raises price cap on hydro," *Globe and Mail*, November 26, 2003.

28 Figures are estimated from Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: Ministry of Energy, January 2004)

29 This includes the facilities not included in the NAOP: Pickering "B"; Bruce "B"; and Darlington, totalling 12 units and 8,728 MW in generating capacity.

30 See Appendix 2 of this report for details of estimates. Tables assume a 25-year lifetime for units, and an 8–13 year lifetime for refurbished units.

31 Nuclear Engineering International, "2003 World Nuclear Industry Handbook," 126, 127; Ontario Hydro, Quarterly Technical Reports for Pickering Nuclear Generating Station, 1983 to 1993.

32 Comm'l Oper'n: Date of Commercial Operation (commercial operation follows the date of criticality and the date of first power).

33 SD: Shut Down. Pickering Units 1, 2, and 3, and Bruce Units 1 and 2 remain shut down at this time, although Ontario Power Generation describes them as being "laid up," which presumably indicates that they do not consider them to be *permanently* shut down. However, these units are listed as "shut down" by Nuclear Engineering International.

34 Nuclear Engineering International, "2003 World Nuclear Industry Handbook," 126, 127.

35 IMO's June 2003 assessment of system reliability concluded that "reserve margins are forecast to be negative" for most of the July 2003 to December 2004 period. See IMO "18-Month Reliability Forecast."

36 Under business-as-usual models, the IMO projects that Ontario will require about 6,400 MW of additional generating resources over the 2004 to 2013 period. See IMO, "Ontario Demand Forecast from January 2004 to December 2013" (Toronto: IMO, March 2003).

37 This overall picture is consistent with those provided by other sources. See for example, R. D. Torrie and R. Parfett, "Phasing Out Nuclear Power in Canada: Towards Sustainable Energy Futures" (Ottawa: Campaign for Nuclear Phaseout/Torrie Smith Associates, July 2003); see also IMO, "Ontario Demand Forecast from January 2004 to December 2013."

38 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.C.

39 Electricity Conservation and Supply Task Force, "Tough Choices," 20.

40 The IMO forecasts that the summer and winter peak demands will be similar with the summer peak slightly higher by 2,000 MW. The summer peak has been used in this table.

41 Electricity Conservation and Supply Task Force, "Tough Choices."

42 Torrie and Parfett, "Phasing Out Nuclear Power in Canada."

43 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.D.

44 Electricity Conservation and Supply Task Force, "Tough Choices," 51.

45 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 5.C.

46 OPG Review Committee, "Transforming Ontario's Power Generation Company" (Toronto: March 2004). Also known as the Manley Committee, after its chair the Hon. John Manley, former federal Minister of Finance.

47 OPG Review Committee, "Transforming Ontario's Power Generation Company," 20.

48 OPG Review Committee, "Transforming Ontario's Power Generation Company," 3.

49 Torrie and Parfett, "Phasing Out Nuclear Power in Canada."

50 Torrie and Parfett, "Phasing Out Nuclear Power in Canada," Figure 11.

51 The Hon. D. Duncan, Minister of Energy, Notes for Remarks to the Canadian Energy Efficiency Alliance, February 17, 2004.

52 See R. H. Cowart et. al., "Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets" (Montpelier, VT: The Regulatory Assistance Project, June 2001).

53 Recent research by the Pembina Institute suggests that on average, investments in energy efficiency create over 35 person years of employment per $1 million invested. This is approximately four times the employment created by the same amount of investment in energy supply. See B. Campbell, L. Dufay, and R. Macintosh, "Comparative Analysis Employment from Air Emission Reduction Measures" (Drayton Valley: The Pembina Institute, January 1997).

54 For an overview of selected recent energy efficiency initiatives in North America, see Appendix 3 of this report.

55 The Energy Foundation Utility Energy Efficiency Fact Sheet, http://www.ef.org/national/FactSheetUtility.cfm

56 See, for example, C. Moore and A. Miller, *Green Gold: Japan, Germany, the United States and the Race for Environmental Technology* (Boston: Beacon Press, 1994).

57 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.B.

58 See the Energy Star website, http://oee.nrcan.gc.ca/energystar/english/consumers/index.cfm

59 See http://rncan.gc.ca/es/etb/cetc/pdfs/the_power_of_new_technology_microturbines_e.pdf

60 See Office of Energy Efficiency, "Improving Energy Performance in Canada—Report to Parliament Under the Energy Efficiency Act 2001–2002" (Ottawa: Natural Resources Canada, 2003), Figure 4-13.

61 See Appendix 3: "Energy Efficiency Program Case Studies."

62 C. Strickland and J. Nyboer, "Cogeneration in Canada" (Canada Industrial Energy End-Use Data and Analysis Centre, 2002). Report prepared for Natural Resources Canada.

63 For example, consumers are more likely to choose a familiar technology over a new one, even if the cost is the same. Consumers will also favour products with the lowest capital cost, even though their operating cost may be significantly higher.

64 Analysis and Modelling Group, "Canada's Emissions Outlook: An Update" (Ottawa:National Climate Change Process, 2000).

65 Analysis and Modelling Group, "Canada's Emissions Outlook: An Update."

66 When such factors as customer charges, distribution charges, transmission charges, wholesale operations charges, and debt retirement charges are considered, a typical average bill in the City of Toronto works out to 11.7 cents/kWh. In November 2003, the government announced the abandonment of the fixed electricity price of 4.3 cents/kWh as of April 1, 2004, going to 4.7 cents/kWh for the first 750 kWh consumed and 5.5 cents/kWh for consumption beyond that level.

67 In the case of residential retrofit, costs were reduced by 20% to reflect the federal EnerGuide for Homes grants that pay up to 20% of the cost of an energy efficiency retrofit based on EnerGuide audit recommendations.

68 See Appendix 1 of this report for a list of targeted technologies.

69 A hurdle rate is usually defined as the interest rate above which consumers will consider investing in options other than financial institutions.

70 See, for example, Electricity Conservation and Supply Task Force, "Tough Choices," 59.

71 Ontario Medical Association, "The Illness Costs of Air Pollution in Ontario: A Summary of Findings" (Toronto: Ontario Medical Association, June 2000), updated via pers. comm., John Wellner, Environmental Program Director, Ontario Medical Association, January 25, 2003.

72 The cost per kWh saved is equal to the annualized investment cost ($/yr) divided by the annual savings (kWh/yr). The annualized cost of a technology is its capital cost expressed as a series of equal annual payments over its useful life. Using this methodology allows the direct comparison of supply and demand side options for meeting increasing consumption of electricity.

73 BC Hydro, "Conservation Potential Review" (Vancouver: BC Hydro, 2003).

74 IMO, "Ontario Demand Forecast from January 2004 to December 2013, " March 2003.

75 For more information on demand response measures and their potential impact on peak demand, see Navigant Consulting, "Blueprint for Demand Response in Ontario" (Toronto: April 2003), prepared for the IMO.

76 "Effective Green Power Policies," *REFocus*, January/February 2003, 30.

77 "ALTENER Programme—The ENER-IURE Project 'RES Legislation in Germany'" (Forum für Zukunftsenergien: November 1999).

78 See IMO, "Ontario Demand Forecast from January 2004 to December 2013."

79 Large-scale hydro can have major environmental and social impacts. However, development of additional large-scale hydro projects in Ontario seems unlikely, given that most economic large-scale sites have already been developed.

80 The analysis draws significantly on the efforts of the Ontario Wind Power Task Force in its "Industry Report and Recommendations" (September 2001).

81 Ontario Wind Power Task Force, "Industry Report and Recommendations," 16.

82 Ontario Wind Power Task Force, "Industry Report and Recommendations," 17.

83 For an overview of existing OPG hydroelectric facilities in Ontario, see http://www.opg.com/ops/H_locations.asp

84 Ontario Hydro, "Niagara River Hydroelectric Development Project Outline" (Toronto: Ontario Hydro, December 1994). An Adam Beck 3 Project, consisting of an additional tunnel and a few 600–900 MW generating stations is also under consideration, although it is considered to have higher capital costs. Pers.comm., Rick Jennings, Ontario Ministry of Energy, March 16, 2004.

85 Ontario Wind Power Task Force, "Industry Report and Recommendations" (Toronto: The Task Force, September 2001), 75.

86 Figures were provided by e-mail, Paul Norris, President, Ontario Waterpower Association, February 17, 2004.

87 In Ontario this is currently approximately 50%.

88 In the United States, the average cost per KWh of wind-powered electricity fell from 38 cents in 1982 to 4.5 cents in 2001. L. R. Brown, "Eco-Economy: Building an Economy for Earth" (New York: W.W. Norton and Earth Policy Institute, 2001), Figure 5-2.

89 Adapted from Ontario Wind Power Task Force, "Industry Report and Recommendations," 4.

90 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37.

91 Ontario Wind Power Task Force, "Industry Report and Recommendations," 38.

92 Ontario Wind Power Task Force, "Industry Report and Recommendations," 45.

93 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

94 Pers. comm., Jason Edgeworthy, Vision Quest Inc., March 10, 2004.

95 The development of Canada's first manufacturing facility, in the Gaspé region, was announced in March 2004. See Canadian Association for Renewable Energies, "Turbine Manufacturer to Invest $7 Million in Gaspesie" (news release, March 3, 2004).

96 See W. Rowley, A. Westwood, and D. Westwood, "Offshore Wind Energy: The Age-Old Renewable Fuel: Global Prospects," *REFocus*, May/June 2003.

97 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37–38.

98 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37.

99 Ontario Wind Power Task Force, "Industry Report and Recommendations," 16–20.

100 Even if electricity is not used directly for heating, higher use of circulation fans and other HVAC equipment occurs during colder periods.

101 S. Elton, "Toward and New Energy Strategy" (Toronto: Canadian Institute for Environmental Law and Policy and the Ontario Environment Network, 1999), citing Ministry of Energy estimates.

102 Environment Canada "Six successful landfill gas utilization projects demonstrate early actions to reduce greenhouse gases" (news release, March 9, 1999).

103 See Ontario Regulation 232/98.

104 Ontario Wind Power Task Force, "Report and Recommendations," 74.

105 The capacity factors used in this table are as follows: coal 55%; nuclear 65%; existing peaking gas and replaced oil 30%; new and existing hydro 50%; wind 30%; solar PV 30%; landfill/waste generated gas 55%; remaining base load requirement 65%.

106 4,500 MW and 25,000 GWh rather than 7,285 MW and 35,000 GWh.

107 Torrie and Parfett, "Phasing Out Nuclear Power in Canada," 24.

108 IMO, "18 Month Outlook."

109 R. Mackie, "Liberals mull Pickering options," *Globe and Mail*, December 6, 2003.

110 OPG Review Committee, "Transforming Ontario's Power Generation Company," Recommendations V.1 and V.3.

111 J. Spears, "8 Nuclear reactors urged for Ontario," *Toronto Star*, December 31, 2003. AECL has suggested that the operating costs of the reactors would be 4.4 cents per KWh.

112 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 5.B, 49.

113 See Appendix 1 of this report.

114 Pickering Review Panel, "Report of the Pickering 'A' Review Panel." The Task Force concluded that the estimated cost of the retubing of Pickering Unit 4 was $500 million, while the action cost of bringing the unit back into service was $1.25 billion.

115 For a detailed discussion of the impact of the NAOP efforts on OPG's overall financial position see KPMG, "Ontario Power Generation Inc. Financial Review of Operations" (Toronto: KPMG, March 2004).

116 Spears, "8 Nuclear reactors urged for Ontario."

117 Electricity Conservation and Supply Task Force, "Tough Choices," 57.

118 OPG Review Committee, "Transforming Ontario's Power Generation Company," 21.

119 See Appendix 2 in this report for a detailed discussion of the basis of these estimates.

120 See Appendix 2 in this report for a detailed discussion of this issue. The OPG Review Committee estimated a lifetime of 8–14 years for Pickering reactor Unit 1 after refurbishment. See OPG Review Committee, "Transforming Ontario's Power Generation Company," 19.

121 New Brunswick Board of Commissioners of Public Utilities, "Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau Nuclear Generating Facility" (September 24, 2002), 16.

122 The portion of time reactors were available to produce power.

123 See Table 4 "CANDU Performance at Ontario Hydro/Ontario Power Generation 1997–2003" in Appendix 2 of this report. This estimate includes all Ontario units.

124 The *Nuclear Waste Management Act*, 2002, requires that OPG begin to set aside $500 million initially, and $100 million per year for the Nuclear Waste Management Organization (NWMO) created through the act, but the NWMO has yet to make a recommendation regarding a long-term solution to the fuel waste issue.

125 For information on the social, health, and environmental impacts of uranium mining and processing, see Canadian Coalition for Nuclear Responsibility, http://www.ccnr.org/#uranium

126 Ontario Hydro, "Final Annual Report: January 1998–March 1999" (Toronto: Ontario Hydro, 1999), 67.

127 See Appendix 4 "A Comparison of Combustion Technologies for Electricity Generation." Originally published by the Pembina Institute, July 2001.

128 Appendix 4, 6–7.

129 Appendix 4, 2–3.

130 Appendix 4, 7.

131 Appendix 4, 3.

132 Appendix 4, 6.

133 Based on OCAA estimate of 142 GWh per PJ. See Gibbons, "Moving to a Coal-Free Future: Viability of Natural Gas as a Fuel for a Coal Phase-Out" (Toronto: Ontario Clean Air Alliance, September 2003), 4.

134 The Ontario Clean Air Alliance estimates that there is currently 416 PJ in additional capacity available through the TransCanada pipeline system. See Gibbons, "Moving to a Coal-Free Future," 8–9.

135 Gibbons, "Moving to a Coal-Free Future," 9.

136 J. Spears "Big chill ahead for Ontario energy," *Toronto Star*, February 24, 2004.

137 Cited in "Backgrounder: No price break for Albertans from 'cheap' coal fired power" (Drayton Valley: The Pembina Institute, November 2001).

138 "Canada's Energy Future" (Ottawa: National Energy Board, 2003), Appendix A, Table A6.1.

139 Gibbons, "Moving to a Coal-Free Future," 8.

140 Electricity Conservation and Supply Task Force, "Tough Choices," 53.

141 See for example, Gibbons, "Moving to a Coal-Free Future," 10, citing NYMEX Natural Gas Spot and Futures Prices January 2002–August 2009.

142 EDC Associates, "Electricity Price, Energy Production and Emissions Impact Evaluating proposed management scenarios for reducing air emissions of 5 priority substances from electricity generation facilities in Alberta: Optimized Scenario and Sensitivity Results prepared for CASA" (Edmonton: EDC Associates, November 2003), 24, Figure 1.

143 Data is from CIMS analyses presented in section 3.4. of this report.

144 No recent levelized cost information could be found for industrial and commercial cogeneration in Ontario. These estimates are from "Evaluation and Recommendations for Saskatchewan's Electric Options 2003–2020" (Saskatchewan Energy Conservation and Development Authority, July 1994), adjusted for inflation.

145 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

146 Ontario Hydro, "Final Annual Report: January 1998–March 1999," 67.

147 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

148 Ontario Wind Power Task Force, "Industry Report and Recommendations," 74.

149 "New Energy Directions: A Low-Cost, Low-Risk Electricity Supply Strategy for Ontario" (Toronto: distributed by the Ontario Clean Air Alliance, March 2004), Appendix B. This estimate is based on the U.S. Department of Energy 's January 2004 forecast that the wellhead price of natural gas in 2010 will be $3.40 per thousand cubic feed (2002 US$). Note that the PIAD estimate for Alberta 2001 of the overall levelized cost to produce electricity was 4.9 cents/kWh.

150 Ontario Hydro "Final Annual Report: January 1998–March 1999," 67. This cost estimate does not include nuclear waste management costs, decommissioning costs, direct and indirect subsidies, and life-cycle externalities of uranium production, or commercial return on capital. The provisions of the federal *Nuclear Waste Management Act*, 2002, require that OPG set aside $500 million initially plus $100 million per year for waste management costs. This would add approximately 0.2 cents per kWh to the cost of nuclear energy. However, this level of funding is inadequate to address long-term waste management. The estimated cost of AECL's long-term deep geological proposal for high-level waste presented to the Nuclear Fuel Waste Management and Disposal Concept Environmental Assessment Panel was $17–$19 billion.

151 Appendix 4, 7.

152 From section 3. Note that this is the required incremental investment, not net societal cost. Energy savings resulting from the investment would permit energy consumers to recover over 96% of their investment over the study period.

153 On the costs and potential for cogeneration in Ontario see Hagler Baily Canada et. al., "Potential for Cogeneration in Ontario: Final Report" prepared for the Ontario Ministry of Energy, Science and Technology, March 2000.

154 Ontario Wind Power Task Force, "Industry Report and Recommendations," 45.

155 Appendix 4, 7.

156 Based on refurbishment of total nuclear capacity 12,626 MWe (net) at a cost of $14.2–$19.2 billion

157 Based on AECL proposal for eight 700 MW units at a total cost of $12 billion.

158 Appendix 4, 7.

159 See the discussion of CIMS results in section 3.4.

160 This is an estimate, assuming construction time would be similar to that for CCNG.

161 Electricity Conservation and Supply Task Force, "Tough Choices," 50.

162 Estimate, assuming construction time similar to CCNG.

163 Construction time following approval. Approvals are already in place for some CCNG facilities in Ontario.

164 Based on Pickering Unit 4 experience and OPG Review Committee, "Transforming Ontario's Power Generation Company," 50.

165 Electricity Conservation and Supply Task Force, "Tough Choices," 57. This is based on an assumption of 2 years for approvals.

166 Same as CCNG, plus time for construction of gasification facility.

167 Assuming no new large-scale hydro.

168 Assuming a capacity factor of 80%, this would require 15,306 MW of nuclear generating capacity.

169 15,306 MW of capacity assuming AECL's proposal for new nuclear at $2.1million/MW as per Table 5.8.

170 This assumes the $18.2 billion investment in energy efficiency measures described in Table 3.8, and $4.5 billion in new CCNG at $1 million/MW as described in Table 5.8.

171 See Appendix 3 "Energy Efficiency Program Case Studies."

172 The Energy Foundation Utility Energy Efficiency Fact Sheet http://www.ef.org/national/FactSheetUtility.cfm

173 "Internal Evaluation of Energy Star Appliance Program." BC Hydro Power Smart, May 2002.

174 On the impact of these programs in Ontario, see Pollution Probe "Pollution Probe's Submissions with Respect to the January 23, 2004, OEB Staff Report on Demand-Side Management and Demand Response," February 9, 2004.

175 Smart Communities Network 2004, http://www.sustainable. doe.gov/municipal/commdsm.shtml

176 Aquila uses a Shared Savings Mechanism approach based on the power savings and the resource benefits flowing from those savings. The benefits are calculated over the lifetimes of the DSM measures put in place. Aquila receives a share of the total net present value of these life-cycle benefits in the form of rate adjustment.

177 The same applies to power consumers who wish to install their own renewable energy-based power sources such as solar PV systems and sell excess power to the grid. As discussed in section 4, solar PV can play a significant role in shaving summer peak demand. Removing grid connection barriers now will pave the way for solar PV to play a major role in managing power demand in the post-2010 era.

178 Conventional meters run backwards when power is supplied to the grid. This is acceptable when buying and selling tariffs are the same, but not if the tariffs are different.

179 A feed-in tariff is a fixed price paid for power from a designated source (e.g., gas cogeneration of solar PV)—usually higher than the price paid for conventional power. It has been successfully used in Germany and other European countries to kick start the renewable energy industry.

180 That is, the length of payback period a consumer is prepared to tolerate to recover the additional capital cost of more energy efficient equipment through energy savings.

181 See http://www.city.toronto.on.ca/wes/techservices/bbp/

182 See Appendix 3 in this report.

183 The Pembina Institute is current working on a position paper on this policy option.

184 See http://www.oee.ncan.gc.ca

185 See IndEco Strategic Consulting Ltd., "DSM for low-income consumers in Ontario" (Toronto: IndEco, November 2003), prepared for the Canadian Environmental Law Association.

186 Notes for remarks, The Hon. D. Duncan, Minister of Energy, "Choose what works for a change," the Empire Club, Toronto, April 15, 2004.

187 In order to ensure effectiveness and accountability, the agency should be subject to oversight and evaluation by the Provincial Auditor and Environmental Commissioner, and subject to the *Freedom of Information Act* and *Protection of Privacy Act*.

188 American Council For An Energy-Efficient Economy has published several reports on US state approaches to DSM regulation, including M. Kushler and M. Suozzo, "Regulating Electric Distribution Utilities As If Efficiency Mattered" (Washington, DC: American Council For An Energy-Efficient Economy, 1999).

189 On these programs, see Appendix 3 of this report. See also IndEco, "DSM for low-income consumers in Ontario."

190 IndEco, "DSM for low-income consumers in Ontario."

191 The Energy Savings Trust in the UK is financed by a PBC and delivers energy efficiency programs to low-income consumers. See http://www.est.org.uk

192 Distribution of the funds could be managed through a board of trustees reflecting the membership of the energy efficiency partnership proposed in Recommendation 7, including consumer, environmental non-governmental organization, and low-income representatives.

193 Under performance-based rate setting and DSM incentives, a utility is allowed to recover the costs of DSM in its rates.

194 Power sales are to be equal to the reduced demand after energy efficiency gains, fuel switching, and cogeneration.

195 For a detailed discussion of the IMO's recently proposed demand response program see J. Gibbons, "Memo to: IMO re: Achieving significant demand response in Ontario" Pollution Probe, March 17, 2004.

196 Ontario Wind Power Task Force, "Industry Report and Recommendations," 28–29.

197 See W. R. Moomaw, "Assessing Barriers and Opportunities for Renewable Energy in North America," *Environmental Challenges and Opportunities of the Evolving North American Electricity Market Background Paper 9* (Montreal: North American Commission for Environmental Cooperation, June 2002).

198 Germany currently has 7,500 MW of installed wind power capacity.

199 Ontario Wind Power Task Force, "Industry Report and Recommendations."

Appendix 1
Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario

Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario

Final Report to

The Pembina Institute for Appropriate Development

M.K. Jaccard and Associates Inc.

New Westminster, BC

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April 27, 2004

Table of Contents

1 Introduction **58**
- 1.1 Background **58**
- 1.2 Specific Terms Of Reference **58**
- 1.3 Report Outline **59**

2 Method **59**
- 2.1 The Cims Model **59**
- 2.1.1 Modeling The Policy Simulation **63**
- 2.2 Method For Reporting Costs **63**
- 2.3 Cims Electricity And Natural Gas Price Forecasts **64**

3 Results **64**
- 3.1 Business-As-Usual **65**
- 3.2 Unconstrained Cogeneration **67**
- 3.3 Unconstrained Cogeneration + Discount Rate Adjustments **69**
- 3.4 Unconstrained Cogeneration + Reduced Capital Costs **71**
- 3.5 Unconstrained Cogeneration + Combined Effect Of Technology-Specific Scenarios **73**

4 Conclusions **75**

5 Key Caveats **76**

Table of Tables

Table 1 Electricity Price Forecasts used in the CIMS Ontario model (¢/kWh) **64**

Table 2 Natural Gas Price Forecasts used in the CIMS Ontario model ($/GJ) **64**

Table 3 Summary of CIMS Simulations, Electricity Demand, 2000-2020 **65**

Table 4 Summary of CIMS Simulations, Natural Gas Consumption, 2000-2020 **65**

Table 5 Summary of CIMS Simulations, Financial Costs ($ million) **65**

Table 6 Business-as-Usual Electricity Demand (all sectors), Ontario (2000-2020) **66**

Table 7 Electricity Demand by Sector, Business-as-Usual, 2000-2020 (PJ) **66**

Table 8 Natural Gas Consumption by Sector, Business-as-Usual, 2000-2020 (PJ) **67**

Table 9 Electricity Demand by Sector, Unconstrained Cogeneration, 2000-2020 **(PJ) 68**

Table 10 Natural Gas Consumption by Sector, Unconstrained Cogeneration, 2000-2020 (PJ) **68**

Table 11 Financial Costs, Unconstrained Cogeneration ($ million) **69**

Table 12 Electricity Demand by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ) **70**

Table 13 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ) **70**

Table 14 Financial Costs, Unconstrained Cogeneration + Discount Rate Adjustments ($ million) **71**

Table 15 Electricity Demand by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ) **72**

Table 16 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ) **72**

Table 17 Financial Costs, Unconstrained Cogeneration + Reduced Capital Costs ($ million) **73**

Table 18 Electricity Demand by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ) **74**

Table 19 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ) **74**

Table 20 Financial Costs, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, ($ million) **75**

1 Introduction

1.1 Background

The Pembina Institute for Appropriate Development (PIAD) has undertaken an analysis of the electricity sector in Ontario. Their work is motivated by a need to move the province towards a more environmentally and economically sustainable electricity system.

Ontario relies heavily on nuclear and coal-fired generation. In addition to the environmental and health concerns associated with this current generation mix, all of the province's existing nuclear generating facilities will reach the end of their expected operational lives over the next 15 years. In addition, the provincial government has committed to the phase-out of coal fired generation by 2007. A major debate is emerging over the appropriate direction of the province's future electricity investments. There are disagreements about the degree to which energy efficiency programs can be expected to reduce future electricity demand, and by implication the province's future new generation capacity needs.

Given that the current situation provides an opportunity to advance major changes in the province's electricity policy framework, PIAD has undertaken an investigation of the potential impact of increasing investments in efficiency measures, as part of its broader electricity policy study. M.K. Jaccard and Associates (MKJA) agreed to assist PIAD in their analysis by using the CIMS energy-economic model to investigate the potential impact on electricity demand of a generic set of efficiency policy measures, as described in the following section.

1.2 Specific Terms of Reference

CIMS was used to simulate four policy scenarios which represent efforts to substantially increase the penetration of energy-efficient end-use technologies, encourage fuel switching (away from electricity) in the same technologies, and remove institutional constraints to cogeneration. These scenarios were constructed by combining the following three modifications to CIMS in various ways.

Modification 1 reduced the user-perceived private discount rate (on investment decisions) for targeted energy-efficient and fuel switch end use technologies to 8% for technologies in commercial and residential sectors, and 12% for technologies in the industrial sector, including cogeneration. This was done to suggest the impact of a variety of policies such as loan programs and tax measures that would increase the attractiveness of these investments. A list of targeted technologies is provided in Appendix A.

Modification 2 reduced the capital cost of the targeted technologies (except residential retrofit) by 8% to emulate a sales tax reduction or grant towards the cost of the technology. Residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use.

Modification 3 removed restrictions that prevent the penetration of cogeneration in the industrial and commercial sectors so that these users could adopt cogeneration where it was cost effective to do so, up to the limitations provided by the local steam load. It was assumed that in effect, cogeneration operators received the same price for power supplied to the grid and for power purchased.

Results were provided for five runs using the demand-side CIMS sub-models for Ontario. The five runs include 1) a Business-as-Usual (BAU) run, 2) a run in which cogeneration in the model is not constrained, 3) a run incorporating the reduced discount rate scenario, 4) a run incorporating the reduced capital cost scenario, and 5) a run incorporating both reduced discount rates and reduced capital costs. Financial costs and energy consumption were summarized by sub-sector (Residential, Commercial, Iron & Steel, Mining, etc.) for the province of Ontario for each run. New technology acquisition for specific energy-efficient technologies targeted under the different policy simulations were also summarized.

1.3 Report Outline

The methods section that follows describes the CIMS model and explains in some detail how policy simulations were applied in the model. It also explains how the costs associated with the policy scenarios were evaluated and reported. The third section presents and discusses financial costs and energy demand impacts for the policy simulations. Finally, we offer some key caveats and conclusions. Detailed reporting of new technology acquisition for the specific energy-efficient technologies targeted is not included in this report, but was provided directly to PIAD as a spreadsheet file.

2 Method

2.1 The CIMS Model

CIMS simulates energy and GHG emissions in the Canadian economy based on a detailed representation of regional economic sectors and technologies in over 50 unique sub-models. The disaggregated energy picture is calibrated to energy and GHG emissions for 2000.[1] The sub-models are then run using forecasts of

[1] Calibration is principally to Statistics Canada's publication *Quarterly Report on Energy Supply and Demand*, 57-003, and Environment Canada's *Greenhouse Gas Inventory*. Exceptions are energy data for Mining (Annual Survey of Mines Data) and Petroleum Refining (Canadian Industrial Energy Enduse Data and Analysis Centre, Petroleum Refining Survey Data).

industry and sectoral growth based on estimates of economic output growth in *Canada's Emissions Outlook: An Update* (CEOU)[2] to give a BAU forecast of energy and emissions.

CIMS provides a dynamic forecasting picture of sectoral energy use, which includes trends in energy efficiency (for instance from the acquisition of more energy efficient technologies), GHG intensities (for instance from fuel switching) and structural production shifts (for instance, the trend towards electric arc furnaces in steel production, relative to integrated mills). The model bases its choice of new technologies – needed to meet production output growth and the retirement of existing capital stock – on the behaviour of consumers, managers and other decision makers based not only on the lifecycle financial cost of competing technologies, but also on risk, market variance (i.e., the degree to which purchasers face different prices for the same technology) and intangible factors (for instance, performance preferences).[3]

CIMS covers the entire Canadian economy and can connect to an aggregated representation of the US economy. It currently models six provinces and an aggregation of the Atlantic provinces. While the model is simple in operation, it can appear complex because it is technologically explicit and covers the whole economy. This means that all technologies (refrigerators, cars, lamps, industrial motors, steel furnaces, buildings, power plants, etc.) must be represented in the model, including their inter-linkages. Because of the great diversity of technologies in industry, the model is especially large for that sector. Appendix B lists the technologies in the sectors being targeted by this research.

In simulating the effects of a technology-specific action, CIMS also simulates the indirect effects of that action within that sector. For example, by specifying in the model that more efficient motors will be required in the industrial sector, changes in the cost of motor-driven service demand may have an effect on the type of process equipment chosen, and subsequently on other energy service demands in the sector (for example, for steam).

A CIMS simulation involves six basic steps. Steps 4 and 5 were not activated for this project.

1. Assessment of demand
2. Retirement
3. New technology competition / retrofitting
4. Energy supply and demand equilibrium

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[2] Analysis and Modelling Group, 1999.

[3] Discount rates are intended to reflect the rate of return that companies and consumers expect from energy investments, one of the model's reflections of behaviour. External limits are used to reflect portions of the market that would not be eligible for certain technologies due to size or technical limitations. Non-cost parameters are used to simulate market barriers that reduce the penetration of a technology below what would be considered economic.

5. Macro-economic equilibrium
6. Output

1. *Assessment of demand:* Technologies are represented in the model in terms of the quantity of service they provide. This could be, for example, vehicle kilometres travelled, tonnes of paper, or m^2 of floor space heated and cooled. A forecast is then provided of growth in energy service demand.[4] This forecast drives the model simulation, usually in five year increments (e.g., 2005, 2010, 2015, etc.).
2. *Retirement*: In each future period, a portion of the initial-year's stock of technologies is retired. Retirement depends only on age.[5] The residual technology stocks in each period are subtracted from the forecast energy service demand and this difference determines the amount of new technology stocks in which to invest.
3. *New technology competition / retrofitting*: Prospective technologies compete for this new investment so that the outcome approximates what would happen in the real world. Hence while the engine for the competition is the minimization of annualized life cycle costs, these costs are substantially adjusted to reflect market research of past and prospective firm and household behaviour.[6] Thus, technology costs depend not only on recognised financial costs, but also on identified differences in non-financial preferences (differences in the quality of lighting from different light bulbs) and failure risks (one technology is seen as more likely to fail than another). Even the determination of financial costs is not straightforward, as time preferences (discount rates) can differ depending on the decision maker (household vs. firm) and the type of decision (non-discretionary vs. discretionary). The model allocates market shares among technologies probabilistically.[7]

   In each time period, a similar competition occurs with residual technology stocks to simulate retrofitting prior to the new technology stock competition.[8] The same financial and non-financial information is required, except that the capital costs of residual technology stocks are excluded, having been spent earlier when the residual technology stock was originally acquired.

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[4] The growth in energy service demand (e.g., tonnes of steel) must sometimes be derived from a forecast provided in economic terms (e.g., dollar value of output from the steel sector).

[5] There is considerable evidence that the pace of technology replacement depends on the economic cycle, but over a longer term, as simulated by CIMS, age is the most important and predictable factor.

[6] With existing technologies there is often available data on consumer behaviour. However, with emerging technologies (especially the heterogeneous technologies in industry) firms and households need to be surveyed (formally or informally) on their likely preferences. These latter are referred to as stated preferences whereas preferences derived from historic data are referred to as revealed preferences.

[7] In contrast, the optimizing MARKAL model will tend to produce outcomes in which a single technology gains 100% market share of the new stocks.

[8] Where warranted, retrofit can be simulated as equivalent to complete replacement of residual technology stocks with new technology stocks.

CIMS has additional levers that allow the user to constrain in various ways the simulation of equipment acquisition decisions. For instance, *maximum market shares* and *minimum market shares* are set for certain technologies or groups of technologies. Of particular importance to this project are maximum market shares, which have been set for cogeneration technologies. These constrain the share of steam demand that can be met by this technology. This constraint represents institutional barriers to cogeneration regarding grid connection, metering, electricity purchase rates, and grid access to third parties.[9]

4. *Equilibrium of energy supply and demand*: Once the demand model has chosen technologies based on the base case and policy case energy prices, the resulting demands for energy are sent to the energy supply models. These models then choose the appropriate supply technologies, assess the change in the cost of producing energy, and if it is significant send the new energy prices back to the demand models. This cycle goes back and forth until energy prices and energy demand have stabilised at an equilibrium.[10]. As noted above, in the current study, this feature of the model was not used, and a set of fixed energy prices were provided to the demand model (see below).
5. *Equilibrium of energy service demand*: Once the energy supply and demand cycle has stablized, the final demand feedback cycle is invoked (if turned on), which adjusts demand for energy services according to their change in overall price, based on price elasticities. If this adjustment is significant, the whole system is re-run from Step 1 with the new demands. This feature was also not used in the current study.
6. *Output*: Since each technology has net energy use, net energy emissions and costs associated with it, the simulation ends with a summing up of these.

2.1.1 Modeling the Policy Simulation

We used the CIMS model to generate the Business as Usual forecast, and for all policy simulations. Only the sub-models in Ontario that could be targeted with specific electricity efficiency and/or cogeneration technologies were run. The sub-models are: Chemical Product Manufacturing, Commercial, Electricity Generation, Industrial Minerals, Iron and Steel, Metal Smelting and Refining, Mining, Other Manufacturing, Petroleum Crude Extraction, Petroleum Refining, Pulp and Paper, and Residential. All CIMS simulations start in 2000. It is not possible to change the policy emulating parameters used in this analysis from one time period to another. Some adjustments were therefore necessary to ensure that the impacts of the policy changes did not take effect

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[9] For a more complete discussion of institutional barriers to cogeneration, see: M.K. Jaccard & Associates, *Cogeneration Potential in Canada*, *Phase 2*, Prepared for Natural Resources Canada, April 2002 (available on-line at www.cieedac.sfu.ca).

[10] This convergence procedure, modelled after the NEMS model of the US government, stops the iteration once changes in energy demand and energy prices fall below a threshold value. In contrast, the MARKAL model does not need this kind of convergence procedure; iterating to equilibrium is intrinsic to its design.

until 2005. To do this we ran CIMS with the policy simulation applied at the beginning of 2000, and then adjusted the 2005 stock, costs and energy values to be the same as the 2005 BAU values. The same limitations meant that the policy changes had to be maintained through to 2020 even when they may not be needed.

PIAD and MKJA agreed on the efficient technologies to be targeted in the policy scenarios, choosing the top performing technology for each end use.[11] The list of targeted technologies is shown in Appendix A. The same technologies are targeted with the lowered discount rate and the capital cost adjustment. By lowering the discount rate, we are representing an increase in the attractiveness of more energy efficient and less electricity reliant technologies.[12]

We simulated support for more cogeneration in the industrial and commercial models by removing restrictions that limited the penetration of cogeneration (to reflect current institutional barriers). Cogeneration is adopted within a sector sub-model according to that model's competition algorithm for steam and/or heat demand. Cogeneration technologies are also targeted as part of the targeted discount rate reduction and capital cost reduction.

2.2 Method for reporting costs

The costs reported in this study are the differences between the total amount spent on capital, operating, maintenance, and energy under the policy and under the BAU over the life of the technologies. All costs are reported in 1995 dollars with future costs discounted to 2004 using a 10% discount rate. We refer to these costs as 'financial costs'. They represent the anticipated financial costs of firms and households adapting to policy change.[13] The financial costs and benefits of a policy simulation are the differences between the total amount spent on capital, operating, maintenance, and energy under the policy and under the BAU over the life of the technologies. Capital costs of technologies purchased during the modelling period are included, but if the technology life extends beyond 2020, the capital cost only includes the costs occurring up to 2020 (based on the annualised cost of capital using a 10% discount rate). All

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[11] Except when this technology was a custom product not widely available on the market. Then the next most efficient model was targeted

[12] Research during the past thirty years has shown that consumers and firms forego apparently cost-effective investments in energy efficiency -- future savings of energy-efficiency investments are discounted at rates well in excess of market rates for borrowing or saving. (For example see A. Jaffe and R. Stavins, "The Energy-Efficiency Gap: What Does it Mean?" *Energy Policy* 22, 10 (1994): 804-810; J. Scheraga, "Energy and the Environment: Something New under the Sun?" *Energy Policy* 22, 10 (1994): 811-818; R. Sutherland, "The Economics of Energy Conservation Policy," *Energy Policy* 24, 4 (1996): 361-370.) This behaviour is captured in the CIMS technology-choice algorithm. By lowering the discount rates, this simulation represents investment decisions if energy-efficiency investments are evaluated at the market rate for borrowing or saving.

[13] We refer to the anticipated financial cost as an *ex ante* financial costs in other studies. See: M. Jaccard, J. Nyboer, C. Bataille and B. Sadownik, "Modeling the Cost of Climate Policy: Distinguishing Between Alternative Cost Definitions and Long-Run Cost Dynamics," *The Energy Journal* 21, 1 (2003): 49-73.

costs are reported in $1995 with future costs discounted to 2004 using a 10% discount rate.

2.3 CIMS Electricity and Natural Gas Price Forecasts

Business-as-usual electricity and natural gas price forecasts used in the CIMS simulations are shown in Tables 1 and 2 below. These prices are based on the forecasts provided by Natural Resources Canada as part of the CEOU.

Table 1 Electricity Price Forecasts used in the CIMS Ontario model (¢/kWh)

	2000	2005	2010	2015	2020
Commercial	8.30	8.50	9.22	9.98	10.79
Industrial	6.30	5.38	5.83	6.31	6.82
Residential	10.00	10.24	11.11	12.03	13.00

Prices are in 2004 dollars.

Table 2 Natural Gas Price Forecasts used in the CIMS Ontario model ($/GJ)

	2000	2005	2010	2015	2020
Commercial	5.25	5.79	6.41	6.97	7.61
Industrial	3.61	3.97	4.40	4.76	5.18
Residential	6.37	7.01	7.76	8.46	9.25

Prices are in 2004 dollars.

3 Results

Electricity demand, natural gas consumption and financial cost results from the CIMS simulations are summarized in Tables 3, 4 and 5. We discuss each of these five simulations in more detail in the sections below.

Table 3 Summary of CIMS Simulations, Electricity Demand, 2000-2020

Simulation	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Baseline	490.26	500.00	531.94	587.18	650.79
1. Unconstrained Cogeneration Competition	490.26	500.00	520.52	562.12	612.76
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	490.26	500.00	437.51	400.69	391.88
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	490.26	500.00	511.94	546.06	591.62

4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	490.26	500.00	435.22	396.37	386.20

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration).

Table 4 Summary of CIMS Simulations, Natural Gas Consumption, 2000-2020

Simulation	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Baseline	880.11	933.27	964.72	1,019.18	1,077.49
1. Unconstrained Cogeneration Competition	880.11	933.27	980.58	1,054.32	1,130.77
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	880.11	933.27	1,000.05	1,111.90	1,226.56
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	880.11	933.27	978.62	1,052.91	1,130.44
4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	880.11	933.27	992.92	1,097.81	1,207.63

Table 5 Summary of CIMS Simulations, Financial Costs ($ million)

Simulation	Net Cost	Individual Cost		
		Investment	O/M	Energy
1. Unconstrained Cogeneration Competition	-995.90	522.61	578.65	-2,097.16
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	432.61	17,227.90	1,485.04	-18,280.33
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	-1,213.98	1,482.13	696.89	-3,393.00
4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	622.31	18,260.39	1,572.77	-19,210.84

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.1 Business-as-Usual

The business-as-usual (BAU) electricity demand forecast was generated based on parameters and assumptions in CIMS (for instance, production, housing and commercial floor space growth forecasts, energy price forecasts, assumptions about structural change), and is not calibrated to any other

forecast.[14] In the base year (2000), the models are calibrated to Statistics Canada energy consumption data, and total electricity demand in Ontario is within 2% of that reported by Statistics Canada.[15] Table 6 describes total electricity demand for all sectors in Ontario between 2000 and 2020, while Table 7 provides a detailed breakdown of the BAU for those sectors targeted in the policy simulations. In these tables, electricity demand refers to the electricity demand met by the electricity supply sector model in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration). Table 8 describes natural gas consumption for the same time period.

Table 6 Business-as-Usual Electricity Demand (all sectors), Ontario (2000-2020)

Unit	2000	2005	2010	2015	2020
PJ	493.3	503	535	591	655
GWh	137,028	139,722	148,611	164,167	181,944

Table 7 Electricity Demand by Sector, Business-as-Usual, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	166.33	174.42	182.70
Metal Smelting and Refining	7.78	8.05	8.53	9.39	10.38
Pulp & Paper	35.76	35.41	34.94	37.19	39.54
Other Manufacturing	64.59	64.29	64.07	65.24	66.51
Mining	6.52	6.83	7.30	8.11	8.86
Iron & Steel	21.04	22.63	24.36	26.11	27.53
Industrial Minerals	3.70	3.85	4.03	4.44	5.03
Chemicals	17.41	18.48	20.62	23.40	26.16
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.44	0.49	-1.33
Residential Sector	153.70	136.53	132.03	138.35	145.93
Commercial Sector	172.70	199.00	233.59	274.41	322.16
Total -- All Sectors	490.26	500.00	531.94	587.18	650.79

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

[14] CIMS estimation of future demand and supply can be calibrated to other forecasts (e.g., in its federal government climate policy analysis), however this step was not included in this analysis.
[15] Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada 2000 – IV* (Ottawa: Ministry of Industry, 2001), p. 76.

Table 8 Natural Gas Consumption by Sector, Business-as-Usual, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.98	405.56	426.33
Metal Smelting and Refining	11.47	13.25	14.52	15.85	17.36
Pulp & Paper	42.63	46.85	50.22	53.73	57.22
Other Manufacturing	169.20	175.83	176.84	177.45	178.75
Mining	1.47	2.80	3.34	3.90	4.43
Iron & Steel	60.01	61.99	64.04	66.17	68.24
Industrial Minerals	6.46	6.33	6.23	6.64	7.50
Chemicals	35.77	40.06	45.05	51.12	57.07
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	24.72	30.70	35.77
Residential Sector	320.30	350.14	367.54	391.21	418.06
Commercial Sector	220.50	216.33	212.20	222.40	233.10
Total -- All Sectors	880.11	933.27	964.72	1,019.18	1,077.49

3.2 Unconstrained Cogeneration

In this simulation, constraints to cogeneration in CIMS were removed (noted in section 2.1), and cogeneration technologies were allowed to compete equally with boilers to meet steam demand. Relative to the BAU, the greatest increases in cogeneration occur in the Commercial, Petroleum Refining and Other Manufacturing. The Chemicals Manufacturing, Iron and Steel, and Pulp and Paper industry sectors already meet a significant portion of their steam and electricity demand by cogeneration in the BAU, which remains unchanged in the unconstrained cogeneration simulation (this does change with technology specific targeting in the policy scenarios). Cogeneration is not available (in the CIMS model) to the Residential, Petroleum Extraction and Mining sub-models.

The simulation results in a 6% drop overall in (utility) electricity demand in the targeted demand sectors. Table 9 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 10 describes natural gas consumption for the same time period.

A detailed breakdown of costs is shown in Table 11. The net discounted financial cost for the simulation period is -$1 billion ($1995) – i.e. a net financial benefit to the users of cogeneration.

The results here are generally consistent with an earlier study conducted by MKJA, which examined the potential of cogeneration in Canada.[16]

[16] Though provincial results were not reported in the study's report, the contractor reviewed output files to ensure that the simulation runs were set up in a similar fashion to that study's 'unconstrained case' and that found that the Ontario reports from the CIMS model were fairly consistent. Changes to the CIMS model has occurred in the intervening years, so results cannot be exactly the same. M.K. Jaccard & Associates, *Cogeneration Potential in Canada, Phase 2* Prepared for Natural Resources Canada, April 2002.

Table 9 Electricity Demand by Sector, Unconstrained Cogeneration, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	166.02	173.75	181.70
Metal Smelting and Refining	7.78	8.05	8.53	9.39	10.38
Pulp & Paper	35.76	35.41	34.94	37.19	39.54
Other Manufacturing	64.59	64.29	64.05	65.22	66.47
Mining	6.52	6.83	7.30	8.11	8.86
Iron & Steel	21.04	22.63	24.36	26.11	27.53
Industrial Minerals	3.70	3.85	4.03	4.44	5.03
Chemicals	17.41	18.48	20.62	23.40	26.16
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.14	-0.15	-2.30
Residential Sector	153.70	136.53	132.03	138.35	145.93
Commercial Sector	172.70	199.00	222.47	250.02	285.12
Total -- All Sectors	490.26	500.00	520.52	562.12	612.76

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration). A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 10 Natural Gas Consumption by Sector, Unconstrained Cogeneration, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	383.97	403.41	422.89
Metal Smelting and Refining	11.47	13.25	14.52	15.85	17.36
Pulp & Paper	42.63	46.85	50.22	53.73	57.22
Other Manufacturing	169.20	175.83	176.86	177.49	178.82
Mining	1.47	2.80	3.34	3.90	4.43
Iron & Steel	60.01	61.99	64.04	66.17	68.24
Industrial Minerals	6.46	6.33	6.23	6.64	7.50
Chemicals	35.77	40.06	45.05	51.12	57.07
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	23.69	28.50	32.25
Residential Sector	320.30	350.14	367.54	391.21	418.06
Commercial Sector	220.50	216.33	229.07	259.70	289.83
Total -- All Sectors	880.11	933.27	980.58	1,054.32	1,130.77

Table 11 Financial Costs, Unconstrained Cogeneration ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-20.14	9.86	4.11	-34.11
Metal Smelting and Refining	0.36	0.00	-0.04	0.40
Pulp & Paper	0.08	0.05	0.02	0.01
Other Manufacturing	0.63	1.22	0.42	-1.01
Mining	0.00	0.00	0.00	0.00
Iron & Steel	0.00	0.00	0.00	0.00
Industrial Minerals	0.00	0.01	0.00	-0.01
Chemicals	0.00	0.00	0.00	0.00
Petroleum Extraction	0.00	0.00	0.00	0.00
Petroleum Refining	-21.21	8.58	3.70	-33.50
Residential Sector	0.00	0.00	0.00	0.00
Commercial Sector	-975.76	512.75	574.54	-2,063.05
Total -- All Sectors	-995.90	522.61	578.65	-2,097.16

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.3 Unconstrained Cogeneration + Discount Rate Adjustments

In this scenario, the discount rate applied to targeted energy-efficient, cogeneration and fuel switch end use technologies was reduced to 8% for technologies in commercial and residential sectors, and 12% for technologies in the industrial sector. This scenario is intended to simulate a variety of policies such as loan programs and tax measures that would remove the user perceived barriers that discourage investment in these alternatives. Also, the constraints to cogeneration continued to be removed in CIMS.

Table 12 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 13 describes natural gas consumption for the same time period.

This scenario results in a 40% drop in electricity demand relative to the BAU scenario. The Pulp & Paper, Commercial, Residential, and Petroleum Refining sectors experience significant reductions. Most of the aggregate savings in 2020 occur due to reductions in the Commercial sector, followed by the Residential and Industrial sectors. A detailed breakdown of costs is shown in Table 13. The net discounted financial cost for the simulation period is $433 million ($1995). However, the Commercial sector and several industrial sectors show a net benefit from the scenario. Only in the Residential sector and in five industries is there a net cost.

Table 12 Electricity Demand by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	154.41	152.07	151.14
Metal Smelting and Refining	7.78	8.05	8.14	8.62	9.23
Pulp & Paper	35.76	35.41	29.46	25.99	23.30
Other Manufacturing	64.59	64.29	62.15	62.21	62.49
Mining	6.52	6.83	6.86	7.24	7.59
Iron & Steel	21.04	22.63	23.40	24.28	24.91
Industrial Minerals	3.70	3.85	3.81	3.98	4.30
Chemicals	17.41	18.48	18.40	19.85	21.53
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.14	-0.14	-2.27
Residential Sector	153.70	136.53	111.37	100.90	98.91
Commercial Sector	172.70	199.00	171.73	147.73	141.82
Total -- All Sectors	490.26	500.00	437.51	400.69	391.88

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 13 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.89	406.21	426.86
Metal Smelting and Refining	11.47	13.25	14.69	16.17	17.84
Pulp & Paper	42.63	46.85	50.15	53.87	57.49
Other Manufacturing	169.20	175.83	175.58	174.91	175.07
Mining	1.47	2.80	3.95	5.57	7.11
Iron & Steel	60.01	61.99	66.05	70.40	73.80
Industrial Minerals	6.46	6.33	6.61	7.49	8.87
Chemicals	35.77	40.06	45.04	51.29	57.43
Petroleum Extraction	0.01	0.01	0.02	0.02	0.03
Petroleum Refining	12.29	19.68	22.79	26.48	29.22
Residential Sector	320.30	350.14	350.61	363.68	387.43
Commercial Sector	220.50	216.33	264.55	342.01	412.27
Total -- All Sectors	880.11	933.27	1,000.05	1,111.90	1,226.56

Table 14 Financial Costs, Unconstrained Cogeneration + Discount Rate Adjustments ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-155.94	779.06	257.42	-1,192.42
Metal Smelting and Refining	-40.40	-0.95	-0.81	-38.64
Pulp & Paper	-52.42	414.73	149.04	-616.19
Other Manufacturing	61.87	188.02	79.65	-205.80
Mining	2.95	-8.53	-4.05	15.53
Iron & Steel	52.37	114.66	-15.99	-46.31
Industrial Minerals	-6.47	23.39	-2.06	-27.79
Chemicals	-203.56	17.18	8.89	-229.62
Petroleum Extraction	0.30	0.00	0.00	0.30
Petroleum Refining	29.42	30.57	42.75	-43.90
Residential Sector	855.10	6,312.97	-40.01	-5,417.86
Commercial Sector	-266.55	10,135.87	1,267.63	-11,670.05
Total -- All Sectors	432.61	17,227.90	1,485.04	-18,280.33

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.4 Unconstrained Cogeneration + Reduced Capital Costs

In this scenario the capital cost of targeted energy efficiency and fuel switch technologies and cogeneration technologies were reduced by 8% to emulate a sales tax reduction or grant towards the cost of the technology. Residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use. Also, the constraints to cogeneration continue to be removed in CIMS.

Table 15 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 16 describes natural gas consumption for the same time period.

This scenario results in a 9% drop overall in electricity demand relative to the BAU scenario. This is significantly less than the first policy scenario, but provides a net financial benefit (see below). Most of the aggregate savings in 2020 occur due to reductions in the commercial sector and residential sectors, while industrial sectors only contribute minimally to demand savings. A detailed breakdown of cost is shown in Table 17. The net discounted financial benefit for the simulation period is $1.2 billion ($1995) – all sectors with the exception of three industries show net benefits.

Table 15 Electricity Demand by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	165.00	171.91	179.14
Metal Smelting and Refining	7.78	8.05	8.41	9.15	10.01
Pulp & Paper	35.76	35.41	34.66	36.69	38.82
Other Manufacturing	64.59	64.29	63.82	64.91	66.11
Mining	6.52	6.83	7.19	7.89	8.54
Iron & Steel	21.04	22.63	24.25	25.94	27.32
Industrial Minerals	3.70	3.85	4.00	4.39	4.95
Chemicals	17.41	18.48	20.51	23.12	25.74
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.11	-0.23	-2.41
Residential Sector	153.70	136.53	129.22	133.32	139.69
Commercial Sector	172.70	199.00	217.71	240.82	272.79
Total -- All Sectors	490.26	500.00	511.94	546.06	591.62

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 16 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	383.94	403.52	423.06
Metal Smelting and Refining	11.47	13.25	14.56	15.94	17.49
Pulp & Paper	42.63	46.85	50.23	53.73	57.23
Other Manufacturing	169.20	175.83	176.88	177.52	178.85
Mining	1.47	2.80	3.46	4.24	4.98
Iron & Steel	60.01	61.99	64.20	66.50	68.66
Industrial Minerals	6.46	6.33	6.21	6.58	7.40
Chemicals	35.77	40.06	44.95	51.05	57.03
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	23.44	27.95	31.42
Residential Sector	320.30	350.14	362.85	383.37	408.89
Commercial Sector	220.50	216.33	231.82	266.02	298.48
Total -- All Sectors	880.11	933.27	978.62	1,052.91	1,130.44

Table 17 Financial Costs, Unconstrained Cogeneration + Reduced Capital Costs ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-73.85	22.06	22.10	-118.02
Metal Smelting and Refining	-14.17	-1.52	-0.28	-12.37
Pulp & Paper	-22.11	9.01	2.66	-33.77
Other Manufacturing	-21.06	0.07	0.35	-21.48
Mining	4.63	-4.56	-1.35	10.54
Iron & Steel	-10.18	2.89	-7.64	-5.43
Industrial Minerals	24.31	3.77	18.86	1.68
Chemicals	-16.96	0.76	-0.20	-17.52
Petroleum Extraction	0.03	0.00	0.00	0.02
Petroleum Refining	-18.33	11.64	9.72	-39.69
Residential Sector	-343.71	563.56	-4.63	-902.64
Commercial Sector	-796.43	896.51	679.41	-2,372.34
Total -- All Sectors	-1,213.98	1,482.13	696.89	-3,393.00

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.5 Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios

In this scenario:

1. the capital cost of targeted energy-efficient and fuel switch end use technologies and cogeneration technologies were reduced by 8%;
2. residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use;
3. the constraints to cogeneration were removed in CIMS;
4. the discount rate applied to targeted energy-efficient and fuel switch end use technologies and cogeneration technologies was reduced (8% for commercial and residential; 12% for industrial).

This scenario results in a 41% drop in electricity demand relative to the BAU scenario, showing that the combined scenarios are not additive. Most additional reductions from adding the capital cost reduction occur in the residential sector.

Table 18 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 19 describes natural gas consumption for the same time period.

A detailed breakdown of costs is shown in Table 20. The net discounted financial cost for the simulation period is $622 million ($1995). However, the commercial and industrial sectors show a net benefit. Only the residential sector shows a net cost of $1,001 million ($1995).

Table 18 Electricity Demand by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	153.83	151.03	149.69
Metal Smelting and Refining	7.78	8.05	8.13	8.62	9.22
Pulp & Paper	35.76	35.41	29.40	25.87	23.14
Other Manufacturing	64.59	64.29	62.10	62.13	62.39
Mining	6.52	6.83	6.85	7.23	7.58
Iron & Steel	21.04	22.63	23.34	24.17	24.73
Industrial Minerals	3.70	3.85	3.78	3.92	4.21
Chemicals	17.41	18.48	18.18	19.52	21.11
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	1.99	-0.47	-2.74
Residential Sector	153.70	136.53	109.95	98.20	95.38
Commercial Sector	172.70	199.00	171.44	147.14	141.13
Total -- All Sectors	490.26	500.00	435.22	396.37	386.20

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 19 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.20	404.87	424.92
Metal Smelting and Refining	11.47	13.25	14.69	16.18	17.85
Pulp & Paper	42.63	46.85	49.41	52.37	55.28
Other Manufacturing	169.20	175.83	175.39	174.51	174.49
Mining	1.47	2.80	3.95	5.58	7.11
Iron & Steel	60.01	61.99	66.19	70.70	74.20
Industrial Minerals	6.46	6.33	6.75	7.81	9.39
Chemicals	35.77	40.06	45.02	51.24	57.37
Petroleum Extraction	0.01	0.01	0.02	0.02	0.03
Petroleum Refining	12.29	19.68	22.79	26.47	29.21
Residential Sector	320.30	350.14	345.00	352.80	373.37
Commercial Sector	220.50	216.33	263.72	340.14	409.34
Total -- All Sectors	880.11	933.27	992.92	1,097.81	1,207.63

Table 20 Financial Costs, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-153.24	828.61	272.72	-1,254.57
Metal Smelting and Refining	-41.20	-1.67	-0.93	-38.60
Pulp & Paper	-35.15	459.03	140.57	-634.75
Other Manufacturing	49.98	184.39	77.21	-211.62
Mining	1.06	-9.94	-4.05	15.06
Iron & Steel	62.09	121.75	-10.45	-49.21
Industrial Minerals	20.02	26.11	17.88	-23.97
Chemicals	-228.51	14.88	8.15	-251.54
Petroleum Extraction	0.32	0.02	0.00	0.30
Petroleum Refining	18.14	34.04	44.33	-60.23
Residential Sector	1,000.81	7,220.33	-45.07	-6,174.44
Commercial Sector	-225.26	10,211.45	1,345.12	-11,781.83
Total -- All Sectors	622.31	18,260.39	1,572.77	-19,210.84

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

4 Conclusions

The four generic policy scenarios modelled in the study result in significant reductions in electricity demand, particularly in the second and fourth scenario simulations in which the discount rate applied to targeted energy-efficient, cogeneration and fuel switch end use technologies was reduced to 8% for technologies in the commercial and residential sector, and 12% for industrial. The second scenario, intended to simulate a variety of policies such as loan programs and tax measures that would remove the user perceived barriers that discourage investment in these alternatives, results in a 40% reduction in electricity demand in 2020.

The third scenario, in which the capital costs of the same targeted technologies were reduced by 8% (20% for residential retrofits), resulted in a 9% reduction in electricity consumption. This particular simulation reflects only the competition response to the lower capital costs and does not reflect an 'announcement effect' of a program of this nature which could increase its effectiveness particularly early in a market transformation program.

In scenario four, where the discount rates and capital costs are lowered, and cogeneration is unconstrained, electricity consumption is reduced by 41%. The results show that the electricity savings produced by the individual policy scenarios are not additive. The exact nature of this overlap and interaction between individual scenarios has not been explored in this analysis.

The results provided in this report do not predict the impact of individual policies and programs nor do they endorse specific government policies. They are illustrative of changes to the capital costs and discount rates in the CIMS model, made to represent the potential impact of policies designed to

encourage the adoption of energy efficient technologies and fuel switching away from electricity.

5 Key Caveats

Important caveats are noted below.

Cogeneration simplifications. CIMS' representation of cogeneration does not include the establishment of dedicated generation capacity to supply power to an open electricity market beyond that which would match the current steam or heating load of an industry or commercial building. Also, CIMS does not account for the cyclical and seasonal nature of thermal demand in the commercial sector which results in cogeneration systems being sized for the base thermal load rather than the average assumed by CIMS. The effect of this limitation is to overestimate the amount of cogeneration that is economical. However, CIMS does not include hot water loads in cogeneration simulations. This would smooth out seasonal thermal demand and increase cogeneration potential.

Community energy management not considered. The analysis conducted using CIMS focused on technology and building-specific energy efficiency actions. It did not include potential electricity savings from changes to urban form, industrial siting, and the provision of infrastructure. For instance, the potential of Community Energy Systems (district cooling using lake water, other district energy systems which use waste heat) were not examined. These effects lead to underestimation of the potential savings in the residential and commercial sectors.

HVAC & lighting interactions in commercial. In the commercial sector there are significant interactive effects between energy end-uses and energy efficiency measures that are not modeled in CIMS. For example, the energy demanded by a commercial building's cooling system is affected by the efficiency of the lighting system, the use of office equipment and the building shell. More efficient lighting and office equipment produce less waste heat and thereby lower the load on the cooling system, and more efficient building shells reduce the infiltration of outside weather conditions. Detailed engineering models exist that calculate these interactions for specific building types, but this type of analysis is beyond the scope of the commercial sub-model in CIMS. Electricity savings in the commercial sector are likely to be underestimated for this reason.

CIMS also does not simulate the efficiency gains that could be achieved in new buildings from use of integrated building design and designation process such as Leadership in Energy and Environmental Design (LEED). Savings in heating, cooling and lighting in new commercial buildings are therefore underestimated.

No technology use actions. This study focused on the acquisition (and retrofitting) of technologies over time, and did not examine technology use

actions that influence how current technologies can be operated or maintained to maximize energy efficiency, or behavioural actions to conserve electricity.

Declining capital costs for new technologies. Over a 15 year time horizon, new energy-efficient technologies are likely to have significantly lower capital cost with economies of scale in manufacture and movement up the design learning curve for producers. This could represent a decrease in costs for targeted technologies in future time periods that would enhance the uptake of energy-efficient technologies. CIMS has a function to simulate this relationship, but the projected declining cost curves were not available for most targeted technologies in the sectors covered in this analysis. Including these more extensively would lower the financial costs reported in all policy scenarios, and energy demand in the capital cost reduction scenarios where market penetration was lower.

Social (or welfare) costs of policies have not been assessed. The financial costs reported for this project do not represent the social costs of pursuing these policies. The factors contributing to these social costs are:

> *The financial costs in CIMS do not represent the actual financial costs paid by consumers*
>
> The financial costs reported here do not include estimates of failure risk, and are based on single point estimates of the financial cost differences of technologies. Realized financial costs could be higher because they would include costs associated with the following. First, the risk of premature failure can be higher for new and emerging technologies, which would result in replacement costs sooner than expected.[17] However, most of the technologies targeted in this work are well established alternatives (Energy Star appliances for example), for which the risk is minimal. Second, energy efficient technologies commonly have long payback periods due to higher capital costs, and consumers who choose them loose the option of pursuing a different options in the future.[18] Third, the acquisition, installation, and operating costs faced by consumers will vary across Ontario.[19] This market heterogeneity is captured by a parameter in CIMS, but if consumers faced with higher costs are forced (as opposed to encouraged) to purchase a specific technology, their realized financial costs will be higher than if they had not been forced to make a decision. The potential for this happening is minimal because consumers have been allowed to choose between technologies freely in this work.

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[17] J. Scheraga, "Energy and the Environment: Something New under the Sun?" *Energy Policy* 22, 10 (1994): 811-818.

[18] R. Pindyck, "Irreversibility, Uncertainty and Investment," *Journal of Economic Literature* 29, 3 (1991): 1110-1152.

[19] See A. Jaffe and R. Stavins, "The Energy-Efficiency Gap: What Does it Mean?" *Energy Policy* 22, 10 (1994): 804-810.

Only a partial equilibrium response to policies is provided

Because the CIMS simulation did not incorporate energy supply and demand price feedbacks or macro-economic feedbacks (steps 4 and 5 of the CIMS simulation) only a partial equilibrium portrayal of the response to the policies is provided in the results. Aggregate, macro-economic effects include trade and structural repercussions resulting from changes in energy prices, and in turn the prices of other intermediate and final products.

Where energy efficient technologies achieve substantial market penetration, and there is a lower cost of energy services, a *rebound effect* in consumer demand can occur where consumers reinvest their savings in alternative forms of consumption, which could also entail energy use. The magnitude and nature of this effect is contentious.[20] This effect is not included in these results.

All administrative and program costs are not provided

Estimated government costs for increased personnel, facilities, subsidies and other expenditures (advertising, information brochures, labelling, etc.) to develop and implement the specific programs and policies needed to achieve the modeled savings are not included.

No estimates of changes to consumers' surplus are made

Where there is an indication that particular technologies confer extra value to consumers above their financial costs, compared to their competitors, changing away from those technologies will confer a loss of consumers' surplus. No cost estimate is provided. The magnitude of these costs would be greatest when the new technologies are substantially different from those being replaced. For example, although buses and cars both move people from point A to B, they do so in a substantially different manner. When the existing and replacement technologies are very similar, energy efficient versus standard refrigerators for example, the change in consumers' surplus is negligible.

Externality costs are not included

Externality costs, such as pollution damages, should be included in social cost estimates unless options are being compared in terms of their relative cost-effectiveness in achieving a particular externality reduction target.

Uncertainty about baseline market shares of technologies. The availability and quality of data to inform the current and forecasted market share of technologies vary by sub-sector. The parameters in CIMS reflect best available information; more uncertainty exists in the industrial sectors.

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[20] Schipper, ed., "On the Rebound: The Interaction of Energy Efficiency, Energy Use and Economic Activity," *Energy Policy* 28, 6-7(2000): 351-354.

Uncertainty about technology preferences. While there is some good market information in some cases, we still face considerable uncertainty in our knowledge of the technology-specific, non-cost preferences of firms and households when deciding upon which technology to acquire to satisfy an energy service.

Appendix A - Targeted Technologies

Technologies targeted by the discount rate and capital cost reductions are described in the tables below. Appendix B provides a picture of how these technologies are competed in the CIMS model. The targetted technologies were selected to represent the top-rated technology option for reducing electricity consumption, without increasing use of either coal or oil.[21] In some end-uses, technologies that specifically promote fuel switching (with no energy efficiency gains) were targeted

Table A-1 Targeted Industrial Technologies

Energy End Use	Technology
Auxiliary Services (all Industry)	Direct Drive with Motor Speed Controller, Variable Speed Drive and Direct Coupling
	High Efficiency Airfoil Fan
	High Efficiency Belt Conveyor
	High Efficiency Centrifugal Compressor
	High Efficiency Centrifugal Pump System with Variable Speed Drive
	High Efficiency Rotary Pump System with Variable Speed Drive
	High Efficiency Reciprocating Pump System with Variable Speed Drive
	Efficient Alternating Current Induction Motors
	Synchronous Alternating Current Induction Motors
	Natural Gas Steam Cogeneration Systems
Lighting (all Industry)	Fluorescent Lamps
	Low Pressure Sodium Lamps
Space Conditioning (all Industry)	Space Heating Natural Gas, Efficient
	Space Cooling Electric, Efficient
Chemicals Manufacturing	Production of Hydrogen Peroxide via Oxidization of Liquid Isopropyl Alcohol
	Production of Sodium Chlorate via Electrolysis using Metal Anode Cells
Industrial Minerals	Clinker Finish Grinding using Roller mills with High Efficiency Separation
	Cement Rotary Long Dry Kiln with Waste Heat Recovery and Cogeneration
	Dry Raw Clinker Grinding, Roller Mill
Iron & Steel	Hot Dip Steel Galvanizing using Natural Gas as a Fuel
	Ladle Reheating using Natural Gas as a Fuel
	Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance and Preheated Scrap
	Direct Smelting (ELRED)
	Steel Finishing Mill with Computer Controls
	Steel Roughing Mill with Computer Controls

[21] The electricity use of each technology was evaluated in terms of both electricity used directly at that service node and electricity consumed indirectly (for instance, through auxiliary motor systems that an industrial process technology may employ).

Table A-1 continued.

Energy End Use	Technology
Metal Smelting and Refining	Carbonylation Refining (Nickel Production) Top Blown Rotary Converter (Nickel Smelting, Copper Smelting) Fluidized Bed Roasting (Nickel Smelting) Oxygen Reverbatory Furnace (Nickel Smelting) Refining Furnace with Oxygen Injection (Copper Refining) Flash Furnace For Roasting and Smelting using Natural gas and Petroleum Coke (Copper Smelting) Tank Agitation Leaching and Electrolytic Precipitation (Zinc Smelting) Flash Roaster to Oxidize Zinc Sulphate (Zinc Smelting) Fire Refining with Fractional Distillation (Magnesium Refining) Flash Furnace for Smelting Magnesium Oxide (Magnesium Smelting) Flash Roaster to Calcine Magnesium Oxide (Magnesium Smelting) New Air Compression and Distillation, Cryogenics
Mining	Diesel-Powered Tailing Disposal Fine Grinding of Metal Ores using Computer Control Diesel-Truck Transfer of Metal Ores Diesel-Powered Metal Ores Extraction
Petroleum Refining	Efficient Fluidized Catalytic Cracking Unit using New Catalysts Efficient Vacuum Unit (Mechanical Vacuum System) Hydrogen Production via Increased Efficiency Natural Gas Steam Reformation
Pulp & Paper	Recycled Pulping using Explosion De-inking Mechanical Pulping using Thermopulp® Biodegradable Debarker/Cutter Efficient Disc Refining and Screening Efficient Paper Forming Tomlinson Recovery Furnace Black Liquor Gasification, Computer Control & Cogeneration (Low Odour Configuration, High Solids Firing)

Table A-2 Targetted Commercial / Institutional Technologies

Energy End Use	Technology
Hot Water	High Efficiency Natural Gas Hot Water Tank Reduced Hot Water Use - Low Flow Devices
Building Shell	Windows with High Performance Glazing Roof Insulation Upgrade Wall Insulation Upgrade
Lighting	Energy Efficient Lighting (T12 Fluorescent Lamps, Compact Fluorescent Lamps, 2-Photon lamps) Lighting Redesign
HVAC	High Efficiency Air Condioning Equipment

(Heating Ventilation & Air Conditioning)	Improved HVAC System Control (via Building Automated System (BAS), Facility Management System (FMS), Energy Monitoring and Control System (EMCS)) Variable Air Volume (VAV) System Variable Speed Drive (VSD/VFD) Improved Boiler Controls Temperature Setback High Efficiency Natural Gas Boiler Ground Source Heat Pump (GSHP)
	Natural Gas Cogeneration
Other End-uses	Natural Gas Cooking Equipment High Efficiency Refrigeration Improved Plug Load Efficiency

Table A-3 Targetted Residential Technologies

Energy End Use	Technology
Appliances	Clothes Washer, Top-rated Energy Star Electric Dryer, Top-rated Energy Star Electric Cooking Range, Top-rated Energy Star Freezer, Top-rated Energy Star Dishwasher, top rated Energy Star Refrigerator, top rated Energy Star
Lighting	Compact Fluorescent Lamps
Air Conditioning	High Efficiency Air Conditioning
Hot Water Use	Reduced Hot Water Consumption – Low flow showerhead Reduced Hot Water Consumptions - Tap Aerator
Building Shells and Domestic Heating Systems	Enhanced R-2000 home – new single family home Retrofitted Shell - existing single family home Integrated Natural Gas Furnace and Domestic Hot Water Tank High Efficiency Natural Gas Furnace High Efficiency Electric Intermittent Fan Improved Apartment Shell Improved Other Building Shell
Water Heating	High Efficiency Natural Gas Water Heater High Efficiency Electric Water Heater Solar Water Heating
Other	Photovoltaic Panels

Appendix B – Technologies in CIMS

The groupings below indicate technologies that compete for a given energy service (a service node) in CIMS in which actions are targetted in this analysis. Service nodes that do not offer options that reduce electricity consumption, or which do not represent services in Ontario are not described.

The name of the technology option targetted by the discount rate and capital cost reductions (in Appendix A) may not appear exactly in the tables below. In CIMS the technology option may be competed in more than one energy service competition. For instance, because CIMS models a variety of motor sizes, alternating current induction motors are targetted at each motor size service node). Also, depending on sub-model (sector) structure, more than one technology can be grouped together as a 'package technology'. Targetted CIMS technologies are indicated in italic font in the tables below.

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC

Service/ Process	Technology Option
Direct Drive	Motor Speed Controller V-Belt ***Motor Speed Controller, Variable Speed Drive + Direct Coupling***
Fans and Blowers	Low Efficiency Backward Inclined Fan High Efficiency Backward Inclined Fan Low Efficiency Radial Fan High Efficiency Radial Fan Low Efficiency Airfoil Fan ***High Efficiency Airfoil Fan*** Low Efficiency Vane Axial/Tube Axial Fan High Efficiency Vane Axial/Tube Axial Fan Medium Efficiency Airfoil Fan Medium Efficiency Vane Axial/Tube Axial Fan
Conveyors	Low Efficiency Belt Conveyor ***High Efficiency Belt Conveyor*** Low Efficiency Screw Conveyor High Efficiency Screw Conveyor Low Efficiency Apron Conveyor High Efficiency Apron Conveyor Low Efficiency Chain Conveyor High Efficiency Chain Conveyor Medium Efficiency Belt Conveyor Medium Efficiency Plus Belt Conveyor Medium Efficiency Screw Conveyor Medium Efficiency Plus Screw Conveyor

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC, continued

Service/ Process	Technology Option
Compression Size 1	Low Efficiency Centrifugal Compressor, Size 1-3 ***High Efficiency Centrifugal Compressor, Size 1-3*** Low Efficiency Double Acting Reciprocating Compressor, Size 1-3 High Efficiency Double Acting Reciprocating Compressor, Size 1-3 Low Efficiency Rotary Compressor, Size 1-3 High Efficiency Rotary Compressor, Size 1-3 Low Efficiency Single Acting Reciprocating Compressor, Size 1-3 High Efficiency Single Acting Reciprocating Compressor, Size 1-3 Medium Efficiency Centrifugal Compressor, Size 1-3 Medium Efficiency Double Acting Reciprocating Compressor, Size 1-3 Medium Efficiency Rotary Compressor, Size 1-3 Medium Efficiency Single Acting Reciprocating Compressor, Size 1-3
Compression Size 2	Low Efficiency Centrifugal Compressor, Size 4-6 ***High Efficiency Centrifugal Compressor, Size 4-6*** Low Efficiency Double Acting Reciprocating Compressor, Size 4-6 High Efficiency Double Acting Reciprocating Compressor, Size 4-6 Low Efficiency Rotary Compressor, Size 4-6 High Efficiency Rotary Compressor, Size 4-6 Low Efficiency Single Acting Reciprocating Compressor, Size 4-6 High Efficiency Single Acting Reciprocating Compressor, Size 4-6 Medium Efficiency Centrifugal Compressor, Size 4-6 Medium Efficiency Double Acting Reciprocating Compressor, Size 4-6 Medium Efficiency Rotary Compressor, Size 4-6 Medium Efficiency Single Acting Reciprocating Compressor, Size 4-6
General Pumping Size 1	Inefficient Centrifugal Pump System, Size 1-3 Inefficient Centrifugal Pump w/ VSD, Size 1-3 ***High Efficiency Centrifugal Pump System w/ Variable Speed Drive, Size 1-3*** Medium Efficiency Centrifugal Pump System, Size 1-3
General Pumping Size 2	Inefficient Centrifugal Pump System, Size 4-6 Inefficient Centrifugal Pump w/ VSD, Size 4-6 ***High Efficiency Centrifugal Pump System w/ Variable Speed Drive, Size 4-6*** Medium Efficiency Centrifugal Pump System, Size 4-6
Slurry / Stock Pumping Size 1	Low Efficiency Rotary Pump System, Size 1-3 ***High Efficiency Rotary Pump w/ Variable Speed Drive, Size 1-3*** Medium Efficiency Rotary Pump System, Size 1-3 Sub- High Efficiency Rotary Pump, Size 1-3
Slurry / Stock Pumping Size 2	Low Efficiency Rotary Pump System, Size 4-6 ***High Efficiency Rotary Pump w/ Variable Speed Drive, Size 4-6*** Medium Efficiency Rotary Pump System, Size 4-6 Sub- High Efficiency Rotary Pump, Size 4-6

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC, ,continued

Service/ Process	Technology Option
Precision Pumping Size 1	Inefficient Reciprocating Pump System, Size 1-3 ***High Efficiency Reciprocating Pump System w/ Variable Speed Drive, Size 1-3*** Medium Efficiency Reciprocating Pump System, Size 1-3 Sub- High Efficiency Reciprocating Pump System, Size 1-3
Precision Pumping Size 2	Inefficient Reciprocating Pump System, Size 4-6 ***High Efficiency Reciprocating Pump System w/ Variable Speed Drive, Size 4-6*** Medium Efficiency Reciprocating Pump System, Size 4-6 Sub- High Efficiency Reciprocating Pump System, Size 4-6
Shaft Drive Size 1	Standard Alternating Current (AC) Induction Motor 1-5 Hp, Meets 1997 Minimum Standard ***Efficiency Efficient AC Induction Motor 1-5 Hp***
Shaft Drive Size 2	Standard AC Induction Motor 6-25 Hp, Meets 1997 Minimum Standard *Efficient Motor 6-25 Hp*
Shaft Drive Size 3	Standard AC Induction Motor 26-100 Hp, Meets 1997 Minimum Standard ***Efficient AC Induction Motor 26-100 Hp***
Shaft Drive Size 4	Standard AC Induction Motor 101-200 Hp, Meets 1997 Minimum Standard ***Efficient AC Induction Motor 101-200 Hp***
Shaft Drive Size 5	Standard AC Induction Motor 201-500 Hp Efficient AC Induction Motor 201-500 Hp ***Synchronous AC Induction Motor 201-500 Hp*** Direct Current Motor Generator Electric Motor 201-500 Hp Direct Current Solid State Electric Motor 201-500 Hp Steam Driven Motor 201-500 Hp
Shaft Drive Size 6	Standard AC Induction Motor >500 Hp Efficient AC Induction Motor >500 Hp ***Synchronous AC Induction Motor >500 Hp*** Direct Current Motor Generator Electric Motor >500 Hp Direct Current Solid State Electric Motor >500 Hp Standard Steam Drive Motor >500 Hp
Lighting	Incandescent Lamps ***Fluorescent Lamps*** Mercury Vapour Lamps ***Low Pressure Sodium Lamps*** High Pressure Sodium Lamps Metal Halide Lamps
Space Heating	Space Heating Electric, Efficient Space Heating Heavy Fuel Oil Space Heating Steam, Efficient Space Heating Oil, Efficient Oil Storage Heating Fired by Natural Gas

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC ,continued

Service/ Process	Technology Option
Space Heating	***Space Heating Natural Gas, Efficient***
	Oil Storage Heating Supplied by Steam
	Space Heating Natural Gas
	Space Heating Electric
	Space Heating Steam
	Space Heating Oil
	Space Heating Heavy Fuel Oil
Space Cooling	Space Cooling Electric
	Space Cooling Electric, Efficient

Note: These technologies are modelled uniquely for all industrial sector models in CIMS. The exact representation of technologies relate to the specifications of each industry.

Table B-2 Cross-cutting Industrial Technologies in CIMS: Steam Provision

Service/ Process	Technology Option
Steam Boilers	Boiler @ 600 psig using iron process gas
	Boiler coal @ 600 psig with heat recovery and regenerative burners
	Boiler coal @ 600 psig, mid-size
	Boiler low sulfur residual @ 600 psig with heat recovery
	Boiler low sulfur residual @ 600 psig with heat recovery and regenerative burners
	Boiler low sulfur residual @ 600 psig with regenerative burners
	Boiler low sulfur residual @ 600 psig, mid-size
	Boiler natural gas @ 600 psig
	Boiler natural gas @ 600 psig with heat recovery
	Boiler natural gas @ 600 psig with heat recovery and regenerative burners
	Boiler natural gas @ 600 psig with regenerative burners
	Coke-fired boiler, high efficiency, mid-size, petroleum refining technology
	Heavy fuel oil-fired boiler, high efficiency, mid-size, petroleum refining technology
	Heavy fuel oil-fired boiler, mid-size, petroleum refining technology
	Light fuel oil-fired boiler, high efficiency, mid-sized, petroleum refining technology
	Light fuel oil-fired boiler, mid-sized, petroleum refining technology
	Liquefied petroleum gas-fired boiler, high efficiency, mid-sized, petroleum refining technology
	Liquefied petroleum gas-fired boiler, mid-size, petroleum refining technology
	Natural gas-fired boiler, mid-sized, petroleum refining technology
	Natural gas-fired high efficiency boiler, mid-sized, petroleum refining technology
	Standard coke-fired boiler, mid-sized, petroleum refining technology
	Still gas-fired boiler
	Still gas-fired high efficient boiler

Table B-2 Cross-cutting Industrial: Steam Provision in CIMS, continued

Service/ Process	
Steam Cogeneration	***Cogenerator @ 900 psig using iron process gas*** ***Cogenerator coal steam turbine @ 900 psig with regenerative burners*** ***Cogenerator coal steam turbine @ 900 psig, mid-size*** ***Cogenerator coal steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator high sulfur residual steam turbine @ 900 psig*** ***Cogenerator hog fuel steam turbine @ 900 psig, mid-size*** ***Cogenerator hog fuel steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator low sulfur residual steam turbine @ 900 psig with regenerative burners*** ***Cogenerator low sulfur residual steam turbine @ 900 psig, mid-size*** ***Cogenerator low sulfur residual steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator natural gas steam turbine @ 900 psig with regenerative burners*** ***Cogenerator natural gas steam turbine @ 900 psig, mid-size*** ***Cogenerator natural gas steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Coke-fired cogeneration, high efficiency, mid-sized, petroleum refining technology*** ***Heavy fuel oil-fired cogeneration, mid-sized, petroleum refining technology*** ***Light fuel oil-fired cogeneration, mid-sized, petroleum refining technology*** ***Liquid petroleum gas-fired cogeneration, mid-sized, petroleum refining technology*** ***Natural gas-fired cogeneration, mid-sized, petroleum refining technology*** ***New cogenerator natural gas steam turbine @ 600 psig, large*** ***New cogenerator natural gas steam turbine @ 600 psig, small*** ***Standard coke-fired cogeneration, mid-sized, petroleum refining technology*** ***Still gas top cycle turbine cogeneration***

Note: These technologies are modelled uniquely for all applicable industrial sector models in CIMS. The exact representation of technologies relate to the specifications of each industry. For instance, hog fuel boilers are only available in the pulp and paper sector.

Table B-3 Chemical Products – Process Technologies in CIMS

Service/ Process	Description
Hydrogen Peroxide Electrolysis	Hydrogen Peroxide Process – Anthraquinone ***Production of Hydrogen Peroxide via Oxidization of Liquid Isopropyl Alcohol***
Sodium Chlorate Electrolysis	Production of Hydrogen Peroxide via Electrolysis using Graphite Electrode Cell ***Production of Hydrogen Peroxide via Electrolysis using Metal Anode Cell*** Sodium Chlorate Production with Bipolar Membrane, Caustic By-product

Table B-4 Commercial / Institutional Technologies in CIMS

Service/ Process	Description
Plug Load	Standard Plug Load Efficiency ***Improved Plug Load Efficiency***
Hot Water	Average Efficiency Electric Hot Water Systems Average Efficiency Electric Hot Water Tank with Service Load Reduction Improved Efficiency Electric Hot Water Tank Improved Efficiency Electric Hot Water Tank with Service Load Reduction ***Average Efficiency Electric Hot Water Tank with Solar Heating*** Average Efficiency Natural Gas Hot Water Systems Average Efficiency Natural Gas Hot Water Tank with Service Load Reduction Improved Efficiency Natural Gas Hot Water Tank ***Improved Efficiency Natural Gas Hot Water Tank with Service Load Reduction*** ***Average Efficiency Natural Gas Hot Water Tank with Solar Heating*** Average Efficiency Oil Hot Water Systems
Cooking	Electric Cooking Equipment *Natural Gas Cooking Equipment* Propane Cooking Equipment
Refrigeration	Refrigeration in New Buildings ***High Efficiency Refrigeration***
Building Shell These options are modelled uniquely for specific building segments. Shell efficiency actions are targetted only in building segments in which the action does not result in an increase electricity consumption due to a greater cooling load (Hotel/Motels, Hospitals/Nursing homes, Warehouses, and Miscellaneous)	Existing Shell Existing Shell, Wall Retrofit New Shell New Shell, Roof Upgrade New Shell, Wall Insulation Upgrade New Shell, Windows Upgrade New Shell, Use of Temperature Setback[22] New Shell, Roof and Wall Upgrade New Shell, Windows and Wall Upgrade New Shell, Roof and Windows Upgrade New Shell, Roof, Windows and Wall Upgrade ***New Shell, Roof, Windows and Wall Upgrade; Temperature Setback***

[22] Temperature setback is included here because like the shell options it reduces the heat load.

Table B-4 Commercial / Institutional Technologies in CIMS, continued

Service/ Process	Description
HVAC Systems HVAC efficiency and cogeneration options are modelled as packages for specific building segments: Large retail Small retail Large office Small office Schools/ Universities Hotel/Motels Hospitals/Nursing homes. Not all options are available for each segment. A simplified set of technologies are modelled for Warehouses and Miscellaneous building segments.	Existing HVAC Systems - Electric Heating New HVAC Systems - Electric Heating New HVAC - Electric Heating with More Efficient A/C New HVAC - Electric Heating, Improved HVAC/Ventilation Control (using BAS/FMS/EMCS and VSD/VFD) New HVAC – GSHP New HVAC - GSHP, Improved A/C Efficiency New HVAC - GSHP, and BAS/FMS/EMCS and VSD/VFD ***New HVAC - GSHP, Improved A/C, Improved HVAC System Control (BAS/FMS/EMCS) and VSD/VFD*** New HVAC - Electric Heating, Improved A/C, and BAS/FMS/EMCS
	Existing HVAC Systems - Natural Gas Heating New HVAC Systems - Natural Gas Heating New HVAC - Natural Gas Heating with More Efficient A/C New HVAC - Improved Natural Gas Heating Efficiency (90%) New HVAC - Natural Gas Heating, Improved HVAC/Ventilation Control (using BAS/FMS/EMCS, VSD/VFD and VAV) ***New HVAC - Natural Gas Cogeneration*** New HVAC - Natural Gas Heating, Solar Heating New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, Improved A/C Efficiency ***New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, BAS/FMS/EMCS, VAV and VSD/VFD*** New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, Improved A/C, BAS/FMS/EMCS, VSD/VFD, VAV *New HVAC - Natural Gas Cogeneration, Improved A/C Efficiency* ***New HVAC - Natural Gas Cogeneration, BAS/FMS/EMCS, VSD/VFD VAV*** ***New HVAC - Natural Gas Cogeneration, Improved A/C, BAS/FMS/EMCS, VSD/VFD, VAV*** New HVAC - Natural Gas Heating, Improved A/C, BAS/FMS/EMCS, VSD/VFD and VAV Existing HVAC Systems - Propane Heating New HVAC Systems - Propane Heating Existing HVAC Systems - Oil Heating New HVAC Systems - Oil Heating
High Bay Lighting	New Service / Hallide Lamps ***Upgrade to 2-Photon Lamps***
Service Lighting	New Building Service Area Lighting (T12 fluorescent lamps, Incandescent Lamps) ***New Building Service Area Lighting: T8 Lamps and Compact Fluorescent Lamps***

Table B-4 Commercial / Institutional Technologies in CIMS, continued

Service/ Process	Description
General Area Lighting	Existing Building General Area Lighting New Building General Area Lighting (T12 fluorescent lamps, Incandescent Lamps) New Building General Area Lighting (T12 fluorescent lamps, Incandescent Lamps), Lighting Redesign to Lower lux ***New Building General Area Lighting, T8 Lamps, Compact Fluorescent Lamps***

Notes:

GSHP: Ground Source Heat Pump
VAV: Variable Air Volume
BAS: Building Automated System
FMS: Facility Management System
EMCS: Energy Monitoring and Control System
VSD/VFD: Variable Speed Drive

Table B-5 Industrial Minerals -- Process Technologies

Service/ Process	Description
Finish Grinding	Clinker Finish Grinding using Ball mills Clinker Finish Grinding using Ball mills with High Efficiency Separation Clinker Finish Grinding using Roller mills ***Clinker Finish Grinding using Roller mills with High Efficiency Separation***
Dry Process Kilns (Cement)	Cement Rotary Kiln, Long Dry Standard Process Cement Rotary Kiln, Long Dry Standard Process with High Efficient Cooler Cement Rotary Kiln, Long Dry Preheating Process Cement Rotary Kiln, Long Dry Preheating with Efficient Cooler Cement Rotary Kiln, Long Dry Preheating and Precalcine Cement Rotary Kiln, Long Dry Preheating and Precalcine with Efficient Cooler ***Cement Rotary Kiln, Long Dry Standard Process with Waste Heat Recovery Cogeneration*** Cement Rotary Kiln Long Dry Process with Preheating and Precalcining and Computer Control Cement Rotary Kiln New Dry Preheating Process with High Efficient Cooler Cement Rotary Kiln New Dry Preheating and Precalcine Process with Efficient Cooler)
Dry Raw Grinding	Dry Raw Clinker Grinding Ball Mill ***Dry Raw Clinker Grinding, Roller Mill***

Table B-6 Iron & Steel -- Process Technologies

Service/ Process	Description
Galvanizing	Electro Galvanizing using Natural Gas as Fuel Electro Galvanizing using Oil as Fuel ***Hot Dip Galvanizing using natural gas as fuel*** Hot Dip Galvanizing using oil as fuel
Ladle Preheat	***Ladle Reheating using Natural Gas as Fuel*** Electric Ladle Reheating
Electric Arc Steel	Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls and Preheated Scrap Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance ***Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance and Preheated Scrap***
BOF Steel	Blast/Coke Furnace; Basic Oxygen Furnace (Gas) Blast/Coke Furnace; Basic Oxygen Furnace (Oil) Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Gas) Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Oil) ***Direct Smelting (ELRED); Blast Oxygen Furnace (Gas)*** Direct Smelting; Blast Oxygen Furnace (Oil) HIsmelt Process - Direct Reduced Iron; Blast Oxygen Furnace (Gas) HIsmelt Process - Direct Reduced Iron; Blast Oxygen Furnace (Oil) Corex Process - Direct Smelted Iron; Basic Oxygen Furnace (Gas) Corex Process - Direct Smelted Iron; Basic Oxygen Furnace (Oil) Blast/Coke Furnace; Basic Oxygen Furnace (Gas) Gas recovery Blast/Coke Furnace; Basic Oxygen Furnace (Oil) Gas recovery Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Oil) Gas Recovery Blast Furnace with Plasma Torch; Basic Oxygen Furnace (gas) Gas Recovery
Finishing Mills	Steel Finishing Mill without Computer Controls ***Steel Finishing Mill with Computer Controls***
Roughing Mills	Steel Roughing Mill without Computer Controls ***Steel Roughing Mill without Computer Controls***

Table B-7 Non-ferrous Metal Smelting and Refining -- Process Technologies

Service/ Process	Description
Nickel Refining	***Nickel Carbonylation Refining***
	Nickel Roasting and Retort Refining
	Nickel Electrolytic High Voltage Cell with Matte Anodes
	Nickel Electrolytic Low Voltage Cell with Metal Anodes
Nickel Conversion	***Nickel Top Blown Rotary Converter***
	Nickel Pierce Smith Converter
Nickel Roasting & Smelting	Nickel Flash Furnace Roasting and Smelting - Natural Gas

Table B-7 Non-ferrous Metal Smelting and Refining -- Process Technologies, continued.

Service/ Process	Description
	Nickel Flash Furnace Roasting and Smelting – Oil
	Nickel Flash Furnace Roasting and Smelting - Natural Gas
	Nickel Hearth Roasting and Oxygen Reverbatory Smelting Furnace
	Nickel Fluidized Bed Roasting and Reverbatory Furnace Smelting
	Nickel Fluidized Bed Roasting and Oxygen Reverbatory Furnace Smelting
	Nickel Sinter Roasting and Reverbatory Furnace Smelting
	Nickel Sinter Roasting and Electric Arc Furnace Smelting
	Nickel Fluidized Bed Roasting and Electric Arc Furnace Smelting
	Nickel Hearth Roasting and Electric Arc Furnace Smelting
Copper Refining	Copper Electrolytic Refining Cell with Anode Furnace
	Copper Refining Furnace with Oxygen
Copper Conversion	***Copper Top Blown Rotary Converter***
	Copper Pierce Smith Converter
Copper Smelting	Copper Flash Furnace For Roasting and Smelting - Coal
	Copper Flash Furnace For Roasting and Smelting - Oil
	Copper Hearth Roasting and Electric Arc Furnace Smelting
	Copper Fluidized-Bed Roasting and Electric Arc Furnace Smelting
	Copper Flash Furnace For Roasting and Smelting - Natural Gas, Petroleum Coke
Zinc Hydro Metallurgy	***Zinc Tank Agitation Leaching and Electrolytic Precipitation***
	Zinc Pressure Leaching with Electrolytic Precipitation
	Zinc Pressure Leaching with Electrolytic Precipitation
Zinc Roasting	Fluidized Bed Roaster To Oxidize Zinc Sulphate
	Flash Roaster To Oxidize Zinc Sulphate
Magnesium Refining	***Magnesium Fire Refining with Fractional Distillation***
	Magnesium Electrolytic Refining with New Electrolysis Cell
	Magnesium Electrolytic Refining with Old Electrolysis Cell
Magnesium Smelting	Electro thermal Furnace For Magnesium Oxide

	Vertical Retort Smelter For Magnesium Oxide Blast Furnace Smelter For Magnesium Oxide ***Flash Furnace For Smelting Magnesium Oxide***
Magnesium Roasting	Hearth Roaster To Calcine Magnesium Oxide Fluidized Bed Roaster To Calcine Magnesium Oxide ***Flash Roaster To Calcine Magnesium Oxide***
Cryogenics	Air Compression and Distillation, Cryogenics ***New Air Compression and Distillation, Cryogenics***

Many of the targeted technologies in this sub-sector were selected for fuel switching and do not necessarily represent 'state-of the-art' technologies.

Table B-8 Mining -- Process Technologies

Service/ Process	Description
Underground Mining Tailing Disposal	***Underground Metal Tailings Disposal, Diesel Powered*** Underground Metal Tailings Disposal, Electric Powered
Underground Mining Primary Milling	Fine Grinding of Underground Metal Ores ***Fine Grinding of Underground Metal Ores with Computer Control***
Underground Mining Transportation	Conveyance Transfer of Underground Metal Ores, Electric Conveyors ***Diesel Truck Transfer of Underground Metal Ores***
Underground Mining Extraction	Extraction of Underground Metal Ores, Electric Powered ***Extraction of Underground Metal Ores, Diesel Powered*** Extraction of Underground Metal Ores, Liquefied Petroleum Gas and Diesel Powered Extraction of Underground Metal Ores, Liquefied Petroleum Gas and Electric Powered
Open Pit Mining Tailing Disposal	***Open Pit Metal Tailings Disposal, Diesel Powered*** Open Pit Metal Tailings Disposal, Electric Powered
Open Pit Mining Secondary Crushing	Fine Grinding of Open Pit Metal Ores ***Fine Grinding of Open Pit Metal Ores with Computer Control***
Open Pit Mining Transportation	Conveyance Transfer of Open Pit Metal Ores ***Diesel Truck Transfer of Open Pit Metal Ores***
Open Pit Mining Extraction	Extraction of Open Pit Metal Ores, Diesel ***Extraction of Open Pit Metal Ores, Electric***

Many of the targeted technologies in this sub-sector were selected for fuel switching and do not necessarily represent 'state-of the-art' technologies.

Table B-9 Petroleum Refining -- Process Technologies

Service/ Process	Description
Catalytic Cracking	Standard Fluidized Catalytic Cracking Unit Fluidized Catalytic Cracking with Turbine Power Recovery Train ***Efficient Fluidized Catalytic Cracking Unit using new Catalysts***
Vacuum Distillation	Standard Vacuum Distillation Units - Mechanical Vacuum Pumps ***Efficient Vacuum Unit (Mechanical Vacuum System)*** Low API Feedstock; Efficient Unit
Hydrogen Production	Hydrogen Via Natural Gas Steam Reformation ***Hydrogen via increase efficiency Natural Gas Steam Reformation***

Table B-10 Pulp & Paper -- Process Technologies

Service/ Process	Description
Pulping (Recycled)	Recycled Pulp with Washing Deinking Recycled Pulp with Flotation Deinking ***Recycled Pulp with Explosion Deinking***
Pulping (Mechanical)	Refiner Mechanical Pulper Size two Thermomechanical pulp (TMP) refiner Size two Thermomechanical pulp (TMP) refiner with high speed refiner Size two Thermomechanical pulp (TMP) refiner with large electric vapour recompression Size two Thermomechanical pulp (TMP) refiner with electric vapour recompression and high speed refiner ***Thermopulp*** Chemi-mechanical , Chemi-thermo-mechanical and bleached Chemi-thermo-mechanical pulp
Debark	Ring Style Mechanical Debarker/Cutter Rosser-Head Mechanical Debarker/Cutter ***Biodegradable Debarker/Cutter***
Tissue Stock Prep	Tissue paper conical refining and screening ***Efficient tissue paper disc refining and screening***
Tissue Forming, Pressing & Finishing	Tissue form, press, finish ***Tissue efficient form, press, finish***
Coated Paper Stock Prep	Coated Paper woodfree conical refining and screening ***Efficient coated Paper woodfree disc refining and screening***
Coated Paper Forming, Pressing & Finishing	Woodfree form, press, finish Woodfree form, extended nip press, finish ***Woodfree efficient form, press, finish*** Woodfree efficient form, extended nip press, finish

Uncoated Paper Stock Prep	Uncoated Paper woodfree conical refining and screening ***Efficient uncoated Paper woodfree disc refining and screening***
Uncoated Paper Forming, Pressing & Finishing	Woodfree form, press, finish Woodfree form, extended nip press, finish ***Woodfree efficient form, press, finish*** Woodfree efficient form, extended nip press, finish
Linerboard Stock Prep	Linerboard conical refining and screening ***Efficient linerboard disc refining and screening***

Table B-10 Pulp & Paper -- Process Technologies, continued

Service/ Process	Description
Linerboard Forming, Pressing & Finishing	Linerboard Form, Press, Finish Linerboard Form, Extended Nip Press, Finish ***Linerboard Efficient Form, Press, Finish*** Linerboard Efficient Form, Extended Nip Press, Finish
Newsprint Prep, Form, Press & Finish	Newspaper refine/screen, form, press & finish Newspaper refine/screen, form, press & induction heat finish Newspaper refine/screen, form, extended nip press & finish Newspaper refine/screen form, extended nip press & induction heat finish ***Newspaper refine/screen, efficient form, press & finish*** Newspaper refine/screen, efficient form, press & induction heat finish Newspaper refine/screen, efficient form, extended nip press & finish Newspaper refine/screen, efficient form, extended nip press & induction heat finish
Recovery Furnace	Tomlinson recovery furnace with direct contact evaporator Tomlinson recovery furnace in a low odour configuration Tomlinson recovery furnace with low odour configuration and computer control Tomlinson recovery furnace with low odour configuration, high solids firing and computer control Tomlinson recovery furnace with computer control & cogeneration, 600 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 750 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 900 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 1200 psig with low odour configuration and high solids firing ***Tomlinson recovery furnace black liquor gasification, computer control & cogeneration,1200 PSIG (low odour configuration, high solids firing)*** Tomlinson recovery furnace with direct contact evaporator, Retrofit to Optimized Operation, 5% Greater Steam Production

In Mechanical Pulping, Stone Groundwood Pulping and Explosion Pulping are not included. The first technology is because the technology is outdated, the second because it is not yet seen to be viable.

Table B-11, Residential Technologies

Service/ Process	Description
Other Appliances	Minor Appliances ***Minor Appliances, Photovoltaic Panels***
Clothes Washers	Clothes Washer, Standard Model Clothes Washer, More Efficient ***Clothes Washer, Top-rated Energy Star***
Clothes Dryers	Electric Dryer, Standard Model Electric Dryer, More Efficient ***Electric Dryer, Top-rated Energy Star***
Ranges	Cooking Range, Gas Cooking Range, Electric, Standard Model Cooking Range, Electric, More Efficient ***Cooking Range, Electric, Top-rated Energy Star***
Freezers	Freezer, Standard Model Freezer, More Efficient ***Freezer, Top-rated Energy Star***
Lighting	Incandescent Lamps Krypton Lamps ***Compact Fluorescent Lamps***
Other Non-Appliance Hot Water	Non-Appliance Hot Water ***Non-Appliance, Reduced Hot Water Consumption, Low Flow Showerhead***
Non Machine Dishwasher	Non-Machine Dishwasher, Hot Water Use ***Non-Machine Dishwasher, Reduced Hot Water Use - Tap Aerator***
Dishwasher	Dishwasher Standard Model Dishwasher, More Efficient ***Dishwasher, Top-rated Energy Star***
Refrigeration	Refrigerator, Standard Model Refrigerator More Efficient ***Refrigerator Top-rated Energy Star*** Refrigerator Most Efficient, Custom Made
New Single Family Homes, Shell Options The shell options noted	***Enhanced R-2000*** Enhanced MNECH Standard Shell

are modelled in conjunction with the various heating technology options below	

Table B-11, Residential Technologies, continued

Service/ Process	Description
Existing Single Family Homes, Shell Options This is modelled for two vintages of homes. They are also modelled in conjunction with the various heating technology options below	Existing Shell (non-retrofit) ***Retrofitted Shell***
Single Family Homes, Heating Options	***Electric Heat Pump, 145% efficiency*** Electric Baseboard, 100% efficiency ***Integrated Natural Gas Furnace and Domestic Hot Water*** Natural Gas Furnace, 78% efficiency ***Natural Gas Furnace, 92% efficiency*** Oil Furnace, 68% efficiency
Furnace Air	Electric Intermittent Fan - System Efficiency of 14% ***Electric Intermittent Fan - System Efficiency of 34%***
Space Heating – Apartments	Space Heat Apartment Electric Baseboards 100% Efficiency Space Heat Apartment Natural Gas 65% Efficiency Space Heat Apartment Natural Gas 78% Efficiency Space Heat Apartment Oil 68% Efficiency Space Heat Apartment Better Shell Electric Baseboards 100% Efficiency Space Heat Apartment Better Shell Integrated Furnace and DHW Natural Gas Space Heat Apartment Better Shell, Natural Gas Heating, 78% Efficiency ***Space Heat Apartment Better Shell, Natural Gas Heating, 92% Efficiency*** Space Heat Apartment Better Shell Oil 68% Efficiency
Space Heating -- Other Buildings	Space Heat Other Natural Gas 78% Efficiency Space Heat Other Oil 68% Efficiency Space Heat Other Better Shell Electric Baseboards 100% Efficiency Space Heat Other Better Shell Integrated Furnace and DHW Natural Gas Space Heat Other Better Shell Natural Gas 78% Efficiency ***Space Heat Other Better Shell Natural Gas 92% Efficiency*** Space Heat Other Better Shell Oil 68% Efficiency Space Heat Other Baseboards 100% Efficiency

	Space Heat Other Natural Gas 68% Efficiency
Hot Water Heating This is modelled for apartments and non-apartments separately	Water Heater Oil Natural Gas Baseline Water Heating Natural Gas EF=0.72 Water Heater Electric Generation 0 EF=0.78 ***High Efficiency Natural Gas Water Heater, EF=0.85*** Solar Water Heating

Appendix 2
Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs

Appendix 2: Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs

Contents

1. Background
1.1. Pickering Nuclear Stations
1.2. Bruce Nuclear Stations
1.3. Darlington Nuclear Station
1.4. Ontario's Demand-Supply Plan Hearing
1.5. 1997 Ontario Hydro Reactor Shutdown
1.6. Nuclear Power & Electricity Sector Restructuring in Ontario

2. CANDU Nuclear Performance in Ontario

3. Expected CANDU Lifetimes

4. CANDU Rehabilitation: Unjustifiable Risk
4.1. The Pickering "A" Refurbishment Fiasco
4.2. Bruce "A": Risky Restart
4.3. Estimated Cost of Refurbishment
4.4. Regulatory Opposition to Point Lepreau Refurbishment

Tables

Table 1.
Ontario Power Generation CANDU Reactors: "A" Plant Phaseout Schedule

Table 2.
Ontario Power Generation CANDU Reactors: "B" Plant Phaseout Schedule

Table 3.
Ontario Power Generation Nuclear Capacity (March 2004*)

Table 4.
CANDU Performance at Ontario Hydro / Ontario Power Generation 1997 - 2003 (Capacity Factor)

Table 5.
Fuel Channel & Steam Generator Replacement times (March 31, 1999)

Table 6.
Estimated Refurbishment Costs for Ontario Nuclear Power Plants (Current Dollars)

Figures

Figure 1
Ontario Nuclear Capacity
(Actual 1971-2003, Projected 2004-2019

Figure 2
Lifetime Performance Vs. Age for Ontario Nuclear Power Plants

Figure 3
Average Cumulative Availability Vs. Reactor Age for Ontario Nuclear Program

Figure 4
Annual Energy from Ontario Nuclear Program
(Actual 1971-2001, Projected 2002-2020)

1. Background

CANDU is a registered trademark of Atomic Energy of Canada Limited (AECL) which stands for **CAN**adian **D**euterium **U**ranium reactor. Its generic name is Pressurized Heavy Water Reactor (PHWR), and it uses heavy water (deuterium oxide) as both moderator and coolant. CANDU reactors need about one metric tonne of heavy water for every megawatt of capacity. Heavy water is very expensive to manufacture, making CANDU reactors more expensive than other reactor designs.

The CANDU core is a cylindrical reactor vessel called a calandria, which encloses hundreds of horizontal fuel channels. Each fuel channel consists of a pressure tube inside a calandria tube. Heavy water coolant under pressure runs through the pressure tubes containing the fuel bundles to remove the heat. The heavy water moderator is in the calandria outside of the calandria tubes. Light Water Reactors (both Pressurized Water Reactors and Boiling Water Reactors) require enriched uranium fuel and use a relatively poor moderator (ordinary 'light' water); whereas CANDU reactors use un-enriched uranium, but have a more effective moderator (heavy water) to slow down neutrons and sustain a chain reaction.

CANDU reactors can remain operating while spent fuel bundles are pushed out of a fuel channel on one side of the reactor, and new fuel bundles are loaded in the other. After ten to twenty years, the fuel channels face an increasing risk of catastrophic failure leading to a major Loss of Coolant Accident (LOCA). This occurred in 1983 in a pressure tube of Reactor #2 at the Pickering station in Ontario, when a meter-long rupture forced the shutdown and retubing of all four reactors at Pickering A over a period of ten years.

A prototype CANDU reactor, the Nuclear Power Demonstration (NPD), built at Rolphton, Ontario, began operation in 1962. It was followed by the 220 MW Douglas Point reactor at the Bruce site on Lake Huron. Douglas Point was intended to be the first commercial nuclear plant, when it began operation in 1968, but it was a technological and financial failure that was permanently shut down in 1984, having had a lifetime capacity factor of only about 50% over a lifetime of less than 18 years[1]. In addition to the NPD and Douglas Point reactors, 20 large reactors came into commercial operation in Ontario between 1971 and 1993 (see Tables 1 and 2). As of March 2004, 15 of these reactors were operating (see Table 3). The five other reactors have been shut down for seven years or more

[1] International Atomic Energy Agency, *Operating Experience with Nuclear Power Stations in Member States in 1984*, Vienna, 1986, p. 67.

Table 1.
Ontario Power Generation CANDU Reactors:
"A" Plant Phaseout Schedule

STATION CAPACITY	UNIT	COMM'L OPER'N	FIRST SHUTDOWN	SECOND SHUTDOWN	LIFE
Pickering "A" 4 X 515 MWe (net)	1	07 / 1971	12 / 1983 – 09 / 1987	12 / 1997 - SD	?
	2	12 / 1971	08 / 1983 – 11 / 1988	12 / 1997 - SD	?
	3	06 / 1972	06 / 1989 – 08 / 1991	12 / 1997 - SD	?
	4	06 / 1973	08 / 1991 – 03 / 1993	12 / 1997 - 09 / 2003	13yrs-2016
Bruce "A" 4 X 769 MWe (net)	1	09 / 1977	01 / 1998 - SD		?
	2	09 / 1977	10 / 1995 - SD		?
	3	01 / 1978	01 / 1998 – 02 / 2004		8yrs-2012
	4	01 / 1979	01 / 1998 – 10 / 2003		13yrs-2016

COMM'L OPER'N = date of Commercial Operation (Commercial Operation follows the date of Criticality and the date of First Power)

SD = Shut Down. Pickering units 1,2, and 3, and Bruce units 1 and 2 remain shut down at this time, although Ontario Power Generation describes them as being "laid up",which presumably indicates that they do not consider them to be *permanently* shut down. However, these units are listed as "shut down" by Nuclear Engineering International.

Sources:

Nuclear Engineering International, *2003 World Nuclear Industry Handbook*, pp. 126 & 127.
Ontario Hydro, *Quarterly Technical Reports Pickering Nuclear Generating Station, 1983 to 1993.*
Bruce Power, *Bruce A Restart Project: Environmental Assessment Study Report*, August 2002, Executive Summary, p. 2.

Table 2.
Ontario Power Generation CANDU Reactors:
"B" Plant Phaseout Schedule

STATION CAPACITY	UNIT	COMMERCIAL OPERATION	25 YEARS
Pickering "B" 4 X 516 MWe (net)	5	05 / 1983	2008
	6	02 / 1984	2009
	7	01 / 1985	2010
	8	01 / 1986	2011
Bruce "B" 4 X 860 MWe (net)	5	03 / 1985	2010
	6	09 / 1984	2009
	7	04 / 1986	2011
	8	05 / 1987	2012
Darlington 4 X 881 MWe (net)	1	11 / 1992	2017
	2	10 / 1990	2015
	3	02 / 1993	2018
	4	06 / 1993	2018

COMM'L OPER'N = date of Commercial Operation (Commercial Operation follows the date of Criticality and the date of First Power)

Source: Nuclear Engineering International, *2003 World Nuclear Industry Handbook*, pp. 126 & 127.

Table 3.
Ontario Power Generation Nuclear Capacity
(March 2004*)

Station	Reactors	Total Capacity
Pickering "A"	1 X 515 MWe(net)	515 MWe(net)
Bruce "A"	2 X 769 MWe(net)	1538 MWe(net)
Pickering "B"	4 X 516 MWe(net)	2064 MWe(net)
Bruce "B"	4 X 860 MWe(net)	3440 MWe(net)
Darlington	4 X 881 MWe(net)	3524 MWe(net)
Ontario Power Generation		11081 MWe(net)

* Re-start of the three Pickering A reactors that have remained shut down since December 1997 would add 1545 MWe(net), raising total nuclear capacity to 12626 MWe(net).

1.1. The Pickering Nuclear Stations

In August 1964, AECL and Ontario Hydro reached an agreement to build two 500 MW CANDU reactors at Pickering, Ontario, just east of Toronto on Lake Ontario.[2] This was Canada's first large-scale nuclear power plant. Ontario Hydro chose to build nuclear stations with four reactors each, in order to reduce costs by sharing safety systems and other infrastructure. AECL and Ontario Hydro were engaging in technological leap-frogging, as the Douglas Point reactor did not even reach criticality until November 1966. Many of the mistakes made at Douglas Point had to be corrected while construction was underway at Pickering.

The federal and Ontario governments not only provided most of the financing for Pickering reactors 1 and 2, but also provided Ontario Hydro with what amounted to a performance guarantee. The total cost of the two Pickering reactors (to both the federal government and Ontario Hydro) was reported at $393 to $420 million (dollars of the year).[3] Ontario Hydro has reported that the release estimate for all four reactors in 1965 was $508 million (dollars of the year)[4], and that the total cost for all four Pickering A units was $716 million (dollars of the year).[5]

The four Pickering A reactors maintained reasonable performance until August 1983, when a disastrous pressure tube rupture occurred in Pickering Reactor 2, and all four reactors were shut down in succession to have their pressure tubes replaced. The retubing of the four reactors cost about $1 billion (dollars of the year)[6] -- more than their original capital cost. The shutdown of the four Pickering A reactors was staggered over a ten-year period 1983-1993 (see Table 1, "First Shutdown").

In 1974, construction started on the four Pickering B reactors immediately beside Pickering A. All eight reactors eventually shared common safety systems, including containment and vacuum building, as well as the emergency core cooling system, resulting in a higher risk of accident than at other facilities. The 1974 release estimate for the four Pickering B reactors was $1.585 billion, and the final cost in 1986 was $3.846 billion.[7]

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[2]Wilfrid Eggleston, *Canada's Nuclear Story*, Clarke Irwin, Toronto, 1965, p. 340.

[3]Robin Ann Cantor, *An Analysis of Public Costs and Risks in the Canadian Nuclear Industry*, PhD Dissertation, Department of Economics, Duke University, 1985, p. 69.

[4]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, p. 1.

[5]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

[6]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

[7]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, Attachment 1, p. 1-1.
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Safety Issues at the Pickering "A" Nuclear Station

The Pickering A nuclear station should be shut down permanently for safety reasons alone. Due to its age, the Pickering A station is the only nuclear plant in the western world that has only one emergency shutdown system. All other nuclear plants in Canada and abroad have two complete emergency shutdown systems for back-up. Ontario Power Generation (Ontario Hydro) installed a cheaper alternative in order to save $300 million.[8] The Pickering station is also closer to larger numbers of people than any other nuclear plant in the world. For that reason, regulatory authorities would not allow a new plant to be built at Pickering today.

The Pickering reactors also have a greater risk of accident because the containment and Emergency Core Cooling System are shared between all 8 reactors at the A and B stations. The Bruce and Darlington stations share safety systems between only 4 reactors.

The consequences of an accident at Pickering "A" are potentially much more serious because of its proximity to the Greater Toronto Area. The Pickering "A" reactors have experienced a number of serious accidents, including the following...

August 1, 1983 - Pickering reactor 2 had a major "loss of coolant accident" (LOCA), after a pressure tube had a metre-long rupture. All four reactors at Pickering eventually had to be shut down over a ten-year period to be retubed at a cost of about $1 billion — more than the original capital cost of the station.

November 22, 1988 - Power was increased in Pickering reactor 1 resulting in damage to 36 fuel bundles. The cooling system was contaminated with radioactive iodine, which was released into the community over several weeks following the accident.

September 25, 1990 - Pickering reactor 2 had a "severe flux tilt" - a loss of reactor control with large power shifts in the core. Staff spent two days trying to stabilize the reactor, and the regulator later said it should have been shut down immediately.

August 2, 1992 - Pickering reactor 1 had a heavy water leak from a heat exchanger that resulted in a leak of 2300 trillion becquerels of radioactive tritium into Lake Ontario. This was Canada's worst-ever tritium release, resulting in increased levels of tritium in Toronto drinking water and along the Lake Ontario shoreline from Whitby to Burlington.

December 10, 1994 - Pickering reactor 2 had a major Loss of Coolant Accident (LOCA). A pipe break resulted in a spill of 185 tonnes of heavy water. For the first time in history at a CANDU, the Emergency Core Cooling System was used to prevent a meltdown, and about 200 workers were needed to clean up the radioactive mess.

July 21, 1995 - Two technicians carried out work on the wrong reactor (5 instead of 6),disabling the second fast shutdown system on reactor 5, which was operating at full power at the time.

February 19, 1996 - 500 tonnes of water spilled into the reactor 5 building due to worker error. Safety equipment could have failed due to water damage The accident blew a 30 kg valve component 3 meters in the air and shot water to the reactor building dome.

[8] Irene Kock, *Nuclear Hazard Report 1991-1992*, Nuclear Awareness Project, 1994, p. 4.

April 15, 1996 - Pickering reactor 4 had a heavy water leak from a heat exchanger that released 50 trillion becquerels of tritium into Lake Ontario. The level of tritium in local drinking water peaked at about 100 times the usual level.

October 11, 1996 - Drug paraphernalia were found in the operating islands at the both Pickering nuclear stations. This was one of 5 significant event reports relating to illicit drug and alcohol use at Pickering in 1996.

May 17, 1997 - It was disclosed that Ontario Hydro failed to report the dumping of more than 1000 tonnes of copper, zinc and other metals into Lake Ontario, due to corrosion of brass steam condensers.

1.2. The Bruce Nuclear Stations

Prior to the operation of Pickering Units 1 & 2, Ontario Hydro and Atomic Energy of Canada Limited (AECL) were negotiating construction of larger reactors at the Bruce site, adjacent to the Douglas Point reactor. AECL agreed to finance and construct a heavy water plant at the site, and Ontario Hydro was to be responsible for the nuclear plants.[9] The 1969 release estimate when construction began on the four Bruce A reactors was $930 million (dollars of the year).[10] The final cost was $1.8 billion (dollars of the year).[11] Performance was reasonable until the late 1980s when problems with steam generators and 'fretting' of pressure tubes by fuel bundles began to occur.[12] By 1993, Bruce A performance had decayed to an abysmal load factor of less than 40%.

Unlike the Pickering A and B stations, the four reactors at the Bruce B station are totally separate from Bruce A. The initial release estimate for Bruce B in 1976 was $3.929 billion and the final cost was $5.994 billion (dollars of the year).[13]

1.3. Darlington Nuclear Station

The Darlington nuclear station, with four 881 MWe(net) reactors, is located in the municipality of Clarington, east of Oshawa. Shortly after work began on Darlington in 1978, the partial meltdown at Three Mile Island occurred in 1979. For the first time in Ontario, construction of a nuclear station prompted large protests and construction of the nuclear plant remained highly controversial during the 1980s and early 1990s. Darlington is infamous

[9]Robin Ann Cantor, *An Analysis of Public Costs and Risks in the Canadian Nuclear Industry*, PhD Dissertation, Department of Economics, Duke University, 1985, p. 71.

[10]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, p. 1.

[11]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p. 4.

[12]*Canada Enters the Nuclear Age: A Technical History of Atomic Energy of Canada Limited*, AECL, 1997, pp. 201-202.

[13]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, Attachment 2, p. 2-1.

for its massive capital cost overruns. An early cost estimate for Darlington in 1973 was $2.5 billion,[14] and the initial release estimate in 1978 was $3.950 billion.[15] The final cost in 1993 escalated to $14.4 billion (dollars of the year).

Darlington experienced serious technical problems in its early years. Start-up was initially delayed by problems with the validation of the shutdown system software. In 1990, reactor 2 experienced a three- month delay when a crack in the rotor of the generator was discovered. In 1991, fuel damage and pressure tube damage was discovered which caused major delays. It was eventually determined that this was caused by excessive vibrations from the main heat transport pumps on all four reactors, which were modified.[16]

1.4. Ontario's Demand-Supply Plan Hearing

In December 1989, Ontario Hydro released its Demand Supply Plan, which identified options for the 25-year period 1990-2014.[17] The plan called for construction of up to 15 reactors at four stations, and cost estimates for the plan, including additional fossil and hydro-electric generating stations, ranged from $61 billion to $200 billion.[18] The plan unraveled under scrutiny at environmental assessment hearings and was withdrawn by Ontario Hydro in January 1993.

1.5. The 1997 Nuclear Asset Optimization Plan

On August 13, 1997, Ontario Hydro announced that it would temporarily shut down its oldest seven reactors. The oldest four reactors at Pickering A were shut down at the end of 1997.[19] The three remaining Bruce A reactors were shut down on March 31, 1998. Bruce reactor 2 had already been closed in October 1995. It was the largest single shutdown in the international history of nuclear power -- over 5,000 MW of nuclear capacity. Ontario Hydro's Nuclear Asset Optimization Plan (NAOP) called for the "phased recovery" of its nuclear reactors, including first, "extensive upgrades" to the operating stations: Pickering B, Bruce B, and Darlington. Next, it would bring back into operation the four Pickering A reactors, and

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[14]Brief by J. McCredie, Project Manager Darlington Generating Station, *Demand Supply Plan Hearing Exhibit 539*, March 20, 1992, p. 1.

[15]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991.

[16]Brief by J. McCredie, Project Manager Darlington Generating Station, *Demand Supply Plan Hearing Exhibit 539*, March 20, 1992, p. 3.

[17]Ontario Hydro, *Providing the Balance of Power*, 1989. The report contained four main sections: *Overview*; *Demand Supply Plan Report*; *Plan Analysis*; and *Environmental Analysis*.

[18]"Ontario Hydro Wants up to 15 Nukes", *Nuclear Awareness News*, Winter 1989/1990, pp. 1-4.

[19]"Ontario Hydro Moving Ahead on Major Overhaul of its Production Facilities", *Ontario Hydro News Release*, August 13, 1997. See also: "Results of the Nuclear Performance Advisory Group's Independent Integrated Performance Assessment and their recommended Nuclear Asset Optimization Strategy", *Ontario Hydro Advice of Decision of Board of Directors*, August 12, 1997.

then the four reactors at Bruce A. This was also called the "12/16/20 Plan" after the number of reactors sequentially in operation.

1.6. Nuclear Power & Electricity Sector Restructuring in Ontario

In October 1998 the Conservative government of former Premier Mike Harris passed the *Energy Competition Act* splitting Ontario Hydro into five publicly owned entities. The government's plan was to restructure the electricity sector, eliminating Ontario Hydro's historic monopoly, and introducing competition at both the wholesale and retail levels. Ontario Hydro ceased operation on April 1, 1999, and Ontario Power Generation (OPG), which owns all of the nuclear, fossil and hydraulic generating stations, began operation. The transmission grid and Ontario Hydro's rural retail division were transferred to Hydro One.

At the time of its dissolution, Ontario Hydro had $38.1 billion in debt and liabilities -- largely debt for nuclear projects, including $2.3 billion in nuclear liabilities for decommissioning and radioactive waste management. It was generally recognized that with this debt and its huge burden of expensive and poorly performing nuclear capacity, OPG would go bankrupt in the competitive electricity market. Thus the nuclear plants were said to be 'stranded' assets, and the debt incurred for their construction and rehabilitation was said to be 'stranded' debt. The Ontario government relieved Ontario Hydro's successor companies of most of this stranded debt. OPG was assigned a value of $8.5 billion and a debt of only $3.4 billion. Ontario Hydro negotiated a very high level of stranded debt ($20.9 billion)[20] to improve its position going into competition. This was in effect the world's biggest nuclear bailout, subsidizing the rehabilitation of Ontario Hydro's ailing nuclear fleet, and facilitating re-start of the eight Pickering A and Bruce A reactors.

As part of the restructuring process in Ontario, the government recognized that the effective monopoly of OPG (85% of the market in 2000) was a major impediment to the introduction of competition. Therefore a 'Market Power Mitigation Agreement' was negotiated, which specified that OPG would "within ten years of market opening, [...] reduce its market share of total generating capacity servicing Ontario demand to no more than 35 percent".[21]

However this did not necessarily imply divestiture. On July 11, 2000, OPG announced that it had entered a "leasing agreement" with Bruce Power Partnership for the Bruce A and Bruce B nuclear stations. At the time, Bruce Power was owned 80% by British Energy plc, 15% by Cameco Corporation (a Canadian company mainly conducting uranium mining and refining) and 5% by the unions at the stations.[22] The lease agreement runs until 2018, with an option to extend for 25 years. The detailed terms of the agreement have not been made public, however, it has been stated that OPG will receive an initial payment of $625 million with supplementary payments for the management of high level radioactive waste (spent

[20]Ontario Ministry of Finance, *Stranded Debt Fact Sheet* , April 1, 1999.

[21]Market Design Committee, *Third Interim Report*, October 8, 1998, p. 1-5.

[22]*Bruce Power: About Us*, downloaded February 27, 2001, http://www.brucepower.com/aboutus.htm

fuel), and a share of net revenue.[23] A major concern is that Bruce Power will not bear the full cost of long-term liabilities for decommissioning and radioactive waste management. These liabilities will rest with Ontario Power Generation and ultimately the Government of Ontario and provincial taxpayers.

After repeated delays, the Ontario government finally opened the Ontario electricity market on May 1, 2002. However, faced with volatile and rising electricity prices under the competitive market, the Ontario Government retreated from its commitment to electricity sector competition. It passed the *Electricity Pricing, Conservation and Supply Act* in December 2002, which capped electricity prices at 4.3 cents per kilowatt hour for consumers using up to 250,000 kWh annually. Large customers remained in the competitive market and received rebates under the Market Power Mitigation Agreement for the 12 months ending April 30, 2003. As of May 1, 2003, rebates to the large customers were fixed at 50% of the amount by which the average spot market price exceeded 3.8 cents per kilowatt hour.

Following their election in October 2003, the Liberal government of Premier Dalton McGuinty passed the *Ontario Energy Board Amendment Act* in December 2003. As of April 1, 2004, the fixed price of 4.3 cents/kWh rose to 4.7 cents for the first 750 kWh consumed each month. Above 750 kWh each month, the price rises to5.5 cents. The rules were not amended for customers above 250,000 kWh/yr.

While electricity has been subsidized by capping rates, the reason for high electricity costs has undoubtedly been nuclear power. When Ontario Hydro last publicly acknowledged the price of nuclear power in 1999, it cost 7.721 cents per kilowatt hour.[24] At the time, the cost of hydroelectric electricity was 1.098 cents per kilowatt hour, and the price of fossil-generated electricity was 4.293 cents per kilowatt hour. Since that time, the cost of nuclear power has unquestionably risen.

2. CANDU Nuclear Performance in Ontario

In 2003, the 20 operable reactors owned by Ontario Power Generation ran at an average net capacity factor of 48.69% (See: Table 4). Capacity factor is actual electricity production expressed as a percentage of 100% perfect output. When the Ontario Hydro Board of Directors approved the Nuclear Asset Optimization Plan in 1997, it was assumed that shutdown of the 8 Pickering A and Bruce A reactors would allow Ontario Hydro to concentrate on the restoration of the remaining reactors in the nuclear fleet to a capacity factor of 86%. However, as can be seen in Table 4, instead of improving, nuclear performance has stagnated at historically low levels, below 50% average capacity factor, despite a massive investment of funds for refurbishment.

[23]Ontario Power Generation & Bruce Power, "Ontario Power Generation and Bruce Power Announce Agreement at Bruce Nuclear", *News Release*, July 11, 2001.

[24]*Ontario Hydro Final Annual Report January 1998-March 1999*, p. 67.

Table 4.
CANDU Performance at Ontario Hydro / Ontario Power Generation
1997 - 2003
(Capacity Factor)

Station	Unit	1997	1998	1999	2000	2001	2002	2003
Pickering A	1	87.97	0	0	0	0	0	0
	2	64.23	0	0	0	0	0	0
	3	65.34	0	0	0	0	0	0
	4	0	0	0	0	0	0	18.88
Bruce A	1	20.57	0	0	0	0	0	0
	2	0	0	0	0	0	0	0
	3	57.24	85.6	0	0	0	0	0
	4	39.99	0	0	0	0	0	13.83
Pickering B	5	87.54	76.9	56.26	58.74	66.57	59.38	69.13
	6	75.27	69.0	74.97	61.48	58.45	88.95	73.01
	7	65.44	67.9	98.77	46.90	89.71	94.68	40.03
	8	8.28	77.0	78.19	60.32	78.06	80.45	87.62
Bruce B	5	83.34	81.6	69.74	91.46	65.18	79.53	76.60
	6	63.83	67.5	91.15	62.03	90.85	48.78	97.57
	7	81.96	72.1	84.18	70.63	93.31	63.96	97.25
	8	84.71	59.6	54.86	86.67	72.05	88.50	71.50
Darlington	1	63.15	83.0	93.80	81.86	91.28	85.35	85.67
	2	62.44	80.4	84.53	89.68	76.13	94.93	79.37
	3	53.33	93.8	73.74	84.97	85.99	83.20	89.07
	4	67.03	84.2	81.13	90.78	89.18	97.20	74.36
OH / OPG		56.58	49.93	47.07	44.28	47.84	48.25	48.69

Sources: *Nucleonics Week* and Ontario Power Generation

Figure 2 shows the pattern of performance for each nuclear station in Ontario over time (the multiple reactors at each station are averaged). Typically there is some improvement in performance in the first ten years of operation, but this is followed by a period of extended decline.[25] The performance of the Pickering station is particularly interesting, since there is a modest improvement of performance about year 20, reflecting the retubing of the four reactors 1983-1993. However, the performance decline continues after a relatively short

[25]Charles Komanoff, *Performance Reliability of Ontario Hydro CANDU Plants: What Should be Expected in Future (Revised)*, Coalition of Environmental Groups, November 1992.

period despite the billion-dollar investment. The pattern of nuclear performance decline can be seen more clearly on the composite graph in Figure 3, which averages all nuclear performance in Ontario over time.

It should be noted that good CANDU performance is not guaranteed even during the early years of operation. Ontario Power Generation's newest reactors at the Darlington Nuclear Generating Station experienced severe performance problems during their early years of operation. Reactors 2 (which was started first) had a three-year average capacity (load) factor of 11%, while the first year capacity factor of reactor 1 was 33%. Initial problems included the cracking of the generator rotors. All original rotors had to be replaced with a new design.[26] These first two reactors at the four unit station were also kept closed for extended periods because of unexplained fuel bundle damage in the reactor core.[27] The fuel damage problem, known as "shake and break" was eventually traced to the design of the primary heat transport pumps in relation to the size and shape of the fuel channels at Darlington. The particular equipment chosen resulted in vibrations inside the fuel channels which caused rapid breakdown of the fuel bundles and damage to the pressure tubes. The design of the heat transport pumps had to be changed to stop the resonance of the fuel channels.[28]

CANDU performance world-wide compares poorly to dominant world types of power reactors. According to *Nucleonics Week*,[29] a nuclear industry trade journal, the 2003 average capacity (load) factors for the major competitive reactor types were as follows: Pressurized Water Reactors (259 PWRs) = 82.62%; Boiling Water Reactors (92 BWRs) = 70.23; Pressurized Heavy Water Reactors [30] (41 PHWRs) = 63.28%. While CANDU performance has declined over the last 20 years, nuclear reactors in the United States have been steadily improving from an average capability factor of 62.7% in 1980 to an average of 88.7% in 1999.[31]

While aging is the broad factor associated with declining CANDU performance over time, there are a few specific technical problems that have contributed to worsening performance. The single greatest problem relates to fuel channels — the calandria and pressure tubes that are a unique feature of the CANDU reactor. After only 12 years of operation, Pickering reactor 2 was shut down in 1983 following a rupture in one of its 390 pressure tubes. Reactor 1 was shut down shortly after and reactors 3 and 4 were eventually shut down as well (see "First Shutdown", Table 1). The rupture was due to embrittlement caused by hydrogen absorption in the tube alloy. Although the outage time for each subsequent retubing was reduced through experience at the four Pickering reactors from 5 years to just under two

[26]Atomic Energy Control Board, *AECB Annual Staff Report for 1992*, AECB BMD 93-138, July 27, 1993.

[27]Atomic Energy Control Board, *AECB Annual Staff Report for 1991*, AECB BMD 92-145, July 28, 1992.

[28]Irene Kock, *Nuclear Hazard Report 1991-1992*, Nuclear Awareness Project, 1994, p. 9.

[29]"Gross Generation by Reactor Type and Vendor", *Nucleonics Week*, February 12, 2004, pp. 6-7.

[30]Pressurized Heavy Water Reactor , PHWR, is te generic name for the CANDU reactor design. Not all of these reactors were built by Ontario Hydro/OPG, or AECL. However, the Ontario Hydro/OPG/AECL 2003 average Capacity Factor of 62.11 was even lower than the overall PHWR average of 63.28%.

[31]"Nuclear power in the U.S. stays on improvement track", *Nuclear News*, May 2000, p. 27.

years, this still represents a major performance problem. The problem has not been limited to Pickering A. In 1986 there was tube rupture in Bruce A reactor 2, and other tubes at Bruce A have leaked, causing shutdowns for replacement. The Bruce reactors, however, have not been completely retubed. Although some technical solutions have allowed continued operation without Large Scale Fuel Channel Replacement, the issue of whether reactors should be completely retubed remains a primary factor in the performance, cost effectiveness and safety of all CANDU reactors.

Steam generator problems are the second most serious contributor to performance problems, although these problems are not unique to CANDU reactors. Fouling, corrosion, pitting, and fretting due to vibration are the major causes of tube failure in steam generators. These problems necessitate various expensive and technically difficult remedial programs, and will likely require the eventual replacement of some steam generators. Remedial programs include: improved chemistry control of feedwater; high pressure water jet cleaning; chemical cleaning; increased monitoring of tubes; and computer prediction and modeling of problems. The Bruce A station has had the most steam generator problems, including leaks caused by corrosion fatigue cracking and stress corrosion cracking. The steam generators of Bruce reactor 2 are in the worst condition. [32]

In order of priority, other causes of CANDU performance problems have been identified as turbines, reactors controls, primary heat transport, moderators, fuel handling, containment, emergency cooling, feed water systems, pump motor sets, and a mixture of problems associated with the balance of plant.[33]

3. Expected CANDU Lifetimes

Traditionally, Ontario Hydro and Ontario Power Generation have depreciated nuclear power plants assuming that their life expectancy was 40 years.[34] However, because of the demonstrated need for retubing and major rehabilitation at much earlier dates, this study has assumed that a reasonable estimate of CANDU lifetime is no more than 25 years, in the absence of major rehabilitation expenditures (see Tables 1 and 2). This estimate is consistent with the position of the Canadian Nuclear Association, which has stated...

> It is [...] assumed that all [CANDU] nuclear power plants will have to undergo one major rehabilitation program after 25 years in service to get to the full 40 years. Hence the forecast on availability depends on whether or not a decision is made to rehabilitate a nuclear plant after 25 years in service.[35]

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[32]Dave Turner, "Pulling CANDUs Back from the Brink", *Nuclear Engineering International*, May 1994, pp. 40-41.

[33]Ontario Hydro, Demand-Supply Plan Hearing, *Response to Interrogatory 9.7.148 from the Coalition of Environmental Groups*, October 31, 1991.

[34]See for example: *Ontario Hydro Final Annual Report January 1988-March 1999*, pp. 44-45.

[35]Canadian Nuclear Association, *The Value of Nuclear Power to Canada's CO2 emissions trading system*, October 2003, p. 12.

Ontario Hydro has also estimated periods shorter than 40 years, when major rehabilitation of nuclear plants would be needed for removal and replacement of fuel channels and steam generators. Thus, it can be seen from Table 5 that these dates were also typically close to 25 years after the initial date of first commercial operation.

Table 5.
Fuel Channel & Steam Generator Replacement times
(March 31, 1999)

Station	Time Period	Years past Commercial Operation
Bruce A Reactors 3 & 4	2001-2008	23-29
Pickering B	2008-2012	25-26
Bruce B	2010-2013	26-26
Darlington	2016-2019	26-26

Source: *Ontario Hydro Final Annual Report January 1988-March 1999*, p. 56.

There is a secondary question as to the period of time that reactors can be expected to operate *after* they have undergone retubing and/or rehabilitation. The only evidence in this regard is the experience of the Pickering A station that was retubed 1983-1993. After being retubed, Pickering reactor 1 lasted 10 years 3 months before being shutdown at the end of 1997; Pickering reactor 2 lasted 9 years 1 month; Pickering reactor 3 lasted 6 years 4 months; and Pickering reactor 4 lasted 4 years 9 months (see Table 1).

After being shut down December 31, 1997, Pickering reactor 4 was restarted in October 2003, but OPG has not said how long it expects the reactor to operate. However, in 1997, as part of the Nuclear Asset Optimization Plan, Ontario Hydro suggested that Pickering reactor 4 would require pressure tube replacement in March 2017.[36] This study has therefore assumed that the most recent rehabilitation of Pickering 4 will give a life expectancy of 13 years to the reactor, i.e. until 2016. This estimate is consistent with the estimate of Torrie Smith Associates.[37] This is also consistent with the position of the Ontario Power Generation Review Committee, which estimated a lifetime of 8-14 years for Pickering reactor 1 after refurbishment.[38]

The OPG Review Committee has suggested that the Pickering B plant may last longer.[39] It have suggested that the rehabilitation dates for the Pickering reactors are 2012 to 2016, or 29

[36]Rick Machon, "Option Selection Basis", *Nuclear Asset Optimization Plan (NAOP) Development & Recommendation*, August 11, 1997, p. 16.

[37]Ralph Torrie and Richard Parfett, Torrie Smith Associates, *Phasing out Nuclear Power in Canada: Toward Sustainable Electricity Futures*, Campaign for Nuclear Phaseout, July 2003, p. i.

[38]OPG Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 50.

[39]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 19.

to 30 years after the start of commercial operation. The committee's estimates for Bruce B and Darlington are not inconsistent with the estimates of this study. The OPG Review Committee suggests that rehabilitation dates for Bruce B are 2009-2017 (24 to 30 years post-commercial operation); and for Darlington are 2013-2020 (21 to 27 years post-commercial operation).

Two other reactors have undergone major rehabilitation — Bruce A reactors 3 and 4. Bruce Power has stated that it expects Bruce reactor 3 to operate for 8 years — until 2012, and that Bruce 4 will operate for 13 years, until 2016.[40]

4. CANDU Rehabilitation Risks

As CANDU reactors in Ontario have aged, they have experienced increasing technical problems and poor performance -- typically worsening dramatically after about ten years of operation. Although it was originally assumed that CANDU reactors would last for forty years, they are experiencing serious operational problems much earlier. Ontario Hydro's decision in August 1997 to temporarily shut down its oldest seven reactors was dramatic proof that the early aging of CANDU reactors leads to poor performance and safety problems.[41]

The four Bruce "A" reactors lasted less than half of their expected 40-year lifetimes, before being shut down for long-term repair work. The Pickering "A" reactors lasted only 25 years, despite having been re-tubed 1983-1993.

4.1. The Pickering "A" Refurbishment

In August 1983 a disastrous pressure tube rupture occurred in Pickering Reactor 2, and all four reactors at the Pickering A station were shut down. The pressure tubes of each reactor were replaced in succession over a ten year period. The retubing of the four reactors cost about $1 billion (dollars of the year)[42] -- more than their original capital cost. As noted above, despite this enormous investment, the reactors were shut down just a few years later at the end of 1997 because of technical and performance problems.

The second major refurbishment of the four Pickering reactors began shortly after they were shut down at the end of 1997. This began even while a screening level environmental assessment on the restart project was being conducted by the Canadian Nuclear Safety Commission from 1999-2000. That environmental assessment was widely condemned by environmental and community groups for failing to deal with vital issues such as the possibility of severe accidents, the need for restart, and financial cost.

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[40]Bruce Power, *Bruce A Restart Project: Environmental Assessment Study Report*, August 2002, Executive Summary, p. 2.

[41]Ontario Hydro, "Ontario Hydro moving ahead on major overhaul of its production facilities", *News Release*, August 13, 1997.

[42]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

The Pickering A restart project had experienced significant delays. When the four old Pickering A reactors were first shut down on December 31, 1997, the first reactor (Unit 4) was supposed to restart in June 2000,[43] with the remaining three to be restarted at six month intervals (to be completely operational by June 2002). After repeated delays, reactor 4 only restarted commercial operation in October 2003 — three years and 4 months late. No public commitment has been made for the restart of reactors 1, 2, and 3. If they are restarted at all, it has been suggested that reactors 1, 2, and 3 would be restarted at one-year intervals.[44]

The cost of the Pickering A restart was estimated in 1999 at $780 million for all 4 reactors.[45] However, by September 2002, Ontario Power Generation reported that costs for the project had escalated to $1.025 billion.[46] At that time, OPG estimated that the start-up of Reactor 4 would cost another $230 million, and the other three reactors would cost an additional $300 to $400 million each.[47] Thus the cost for restarting reactor 4 alone was then estimated to be $1.255 billion, with a likely additional $1.2 billion for the other three reactors, totaling $2.455 billion -- three times the original cost estimate.

On May 30, 2003, the Ontario government of former Premier Ernie Eves announced the creation of a review panel on the refurbishment of the Pickering "A" nuclear station. The Sierra Club of Canada labeled the review a "whitewash" because it was had pro-nuclear leadership and because the terms of reference were restricted to determining the conditions for restarting the four reactors, rather than comparing the cost of energy alternatives and the risks of restarting the reactors.[48] The review was headed by a former federal energy minister under the Mulroney government, Jake Epp, well known for his support of nuclear power. The second member of the review was Robin Jeffrey, a nuclear industry insider, formerly head of British Energy in Norther America (British Energy is the British company that created the American nuclear company Amergen and the Canadian nuclear company Bruce Power).

The Epp review panel released its report on December 4, 2003. The panel focused blame on management practices at Ontario Power Generation, almost completely ignoring the antiquated Pickering nuclear technology.[49]

The review stated that $1.25 billion had been spent in order restart reactor 4 by September 2003. Astoundingly, OPG had failed to provide a hard estimate of the cost of completion.

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[43]Ontario Hydro, *1998-200 Ontario Hydro Corporate Business Plan*, February 17 1998, p. 22.

[44]Richard Brennan, "Shake-up at hand over nuclear plant", *Toronto Star*, November 27, 2002, p. A8.

[45]KPMG, *Ontario Power Generation Inc. Financial Review of Operations*, March 15 2004, p. 20.

[46]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002, p. 12.

[47]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002.

[48]Sierra Club of Canada, "Eves Government Pickering Nuclear Review: A One-sided Whitewash", *News Release,* June 3, 2003.

[49]Pickering Review Panel, *Report of the Pickering "A" Review Panel*, December 4, 2003. The three panel members were Jake Epp, Chair, Peter Barnes and Dr. Robin Jeffrey.

The Epp panel guessed that the total cost would be $3 to $4 billion — an incremental amount of $1.75 to $2.75 billion to restart reactors 1, 2, and 3.[50] More than anything else, the $1 billion range of uncertainty about the final cost indicated the enormity and high risk of the Pickering restart project.

The report identified 11 increases of the cost estimate between August 1999 and May 2003, 13 revisions of the return-to-service date in the same period.[51] Little or nothing had changed in management practices at the plant since disastrous problems had been identified in 1997. All of the final recommendations of the panel related to improving corporate governance and managerial practices.

Only one sentence in the entire report, entitled "Complexity of the Project" mentioned the role that the technology might play...

> It should be recognized that the return of the remaining units remains a large, complex project with corresponding cost involving the reconditioning , rebuilding, replacing or adding of equipment at a 30-year-old station.[52]

The Epp panel implicitly supported the continued refurbishment of the other three reactors at Pickering A. However the government of Premier McGuinty was not prepared to make an immediate decision. On December 16, 2003, another panel, known as the Ontario Power Generation Review Committee, was mandated to examine the role, structure and governance of OPG, as well as the proposed restart of reactors 1, 2, and 3 at the Pickering "A" nuclear station. The Committee was headed by former federal Finance Minister John Manley, and again recruited Jake Epp. The third member of the tribunal was Peter Godsoe, Chairman and former CEO of Scotiabank. No energy or environmental experts were appointed to the committee.

The OPG Review Committee released its report on March 18 2004. Similar to the Pickering "A" Review Panel, the OPG review committee placed blame for the problems at OPG's nuclear facilities on management practices. Despite the obvious financial, performance and safety problems of the last 30 years, they found no fault with the nuclear power technology itself.

In the case of the restart of Pickering A reactors 1, 2, and 3, Manley supported the restart project strongly, suggesting that the project be done sequentially, with approval dependent on whether "OPG will be able to succeed at the Unit 1 project".[53] Manley did not even stipulate that OPG should finish the Unit 1 project *on budget*.

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[50] *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 4.

[51] *Report of the Pickering "A" Review Panel*, December 4, 2003, pp. 11 - 12.

[52] *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 15.

[53] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 47.

Manley argued that the Pickering restart project would be cheaper than a Combined Cycle Gas Turbine fired by natural gas. However, the full details of this plan have not been revealed, and the economic analysis of the business case is extremely narrow and limited in a number of respects...

- The comparison of nuclear power is against a Combined Cycle Gas Turbine fired by natural gas. There is no comparison of a CCGT in a Combined Heat and Power (cogeneration) application, in which efficiency could be doubled and costs reduced dramatically.

- The Manley study compares nuclear costs against a gas-fired CCGT, but does not compare costs against a range of conservation/efficiency measures, or renewable energy sources. These green energy alternatives were the basis of the McGuinty government's election promises for the electricity sector.

- There is no discussion about the risk the refurbishment project taking longer than the expected 20 months. Restart of the Pickering 4 reactor was three years and four months late. Late restart will push up the base cost, as well as increasing replacement power costs.

- The sensitivity analysis for plant life does not take into account the risk of much worse performance than the 75 to 90% capacity factor suggested. As noted in Table 4, average performance of the nuclear fleet in 2003 was 49%.

- The study makes no mention of replacement generating costs while the Pickering reactors and others have outages for refurbishment. These costs will likely be extremely large.

- The sensitivity analysis in the business case for plant life after refurbishment does not take into account the risk that lifetimes may be far less than the 8 to 14 years suggested in the analysis.

- The cost of natural gas is condemned as "high and volatile" but absolutely no analysis is provided on natural gas prices, forecasts or possible resource strategies.

- The study does not take into account the possibility that Operation, Maintenance and Administration (OM&A) costs will be much more than the $77 to $108 million per year budgeted.

The Manley Committee not only supported the restart of the Pickering A reactors, but strongly recommended that nuclear power be supported and expanded in Ontario...

> ...we have concluded that Ontario must begin planning now to supplement and ultimately replace its ageing nuclear assets with new and better generations of nuclear technology.[54]

[54]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, pp. 19-20.

This recommendation was based on no analysis -- only a number of incorrect, meaningless, unjustified and/or implausible claims...

"nuclear plants can be a cost-effective source of base-load generation"[55]

In fact, nuclear power in Ontario has been spectacularly expensive, and NOT cost-effective. This was confirmed by OPG's own auditors on March 16, 2004.

"the price of power they [nuclear plants] generate is stable over time."[56]

In fact, the only reliable aspect of the price of nuclear generated electricity in Ontario has been its dramatic increase over time as nuclear performance plummeted and nuclear costs skyrocketed.

"Relying heavily on gas to provide base load would push up the level of Ontario's electricity prices and make them unstable."[57]

The major source of volatility in the electricity market has without question come from nuclear plants that on today and gone tomorrow. The shutdown of 8 reactors (5000 MW) from 1995 to 1998 was an unprecedented example of volatility and unreliability.

"Renewable energy sources, conservation and co-generation are all important, but cannot fully bridge the supply gap."[58]

Manley provided absolutely no evidence to this effect. Evidence provided by intervenors, demonstrated conclusively just the opposite.

"Nuclear power does not contribute to air emissions the way coal and gas do, and does not involve the complex watershed management issues of hydro projects."[59]

Nuclear power plants release a variety of radiologically and chemically toxic chemicals into the air and water. Notable amongst these emissions is radioactive tritium, which is released in large quantities by the CANDU reactor and is known to cause cancer and birth defects.

"While safe long-term disposal of spent fuel is vital, there is a cooperative process under way between the federal and provincial governments to ensure this will be done."[60]

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[55]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[56]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[57]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[58]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[59]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

OPG's reactors had produced about 35,000 tonnes of high level radioactive waste (about 1.5 million spent fuel bundles) by the end of 2002. If these reactors are refurbished and allowed to operate for 40 years, this amount will roughly double. OPG has assessed the cost of disposing of this waste and decommissioning its reactors at $18.2 billion. Independent observers believe that this amount may be significantly underestimated. The Nuclear Waste Management Organization has been mandated to provide a recommendation on long-term management of high-level radioactive waste by November 2005. Because this organization is dominated and governed by the nuclear industry, its ability to make a credible or objective decision has been challenged.

4.2. The Bruce A Restart

In May 2001, Ontario Power Generation (OPG) finalized a deal with Bruce Power (then a subsidiary of British Energy, a nuclear power plant operator in the United Kingdom) for an eighteen-year lease to operate the Bruce nuclear complex on the shore of Lake Huron in Ontario.[61] The details of the agreement were kept secret, but it was clearly a sweetheart deal for Bruce Power.[62] Among other things, Bruce Power had no long-term responsibility for radioactive waste management and reactor decommissioning, responsibility for which remained with OPG, and ultimately with OPG's sole shareholder, the Government of Ontario. Costs for radioactive waste management and decommissioning have yet to be demonstrated, however, Ontario Power Generation has estimated that it will cost about $18.2 billion and take until 2070. About $10 billion of this amount is for radioactive waste management, assuming that deep geological disposal is used, and about $7.4 billion is for decommissioning of the 20 OPG owned reactors (including Bruce A and B).[63] OPG set aside $6.2 billion in 2003, and plans to increase that amount to $8 billion in 2007 and $10 billion by 2010. Yves Giroux, a member of the Canadian Nuclear Safety Commission has expressed doubt about whether the amounts set aside by OPG will be adequate.[64]

The agreement between Bruce Power and OPG was a cash cow for British Energy, earning $120 million profit in its first year of operation.[65] The Bruce complex includes four 769 MW (net) reactors at the Bruce A station and four 860 MW (net) reactors at the Bruce B station.

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[60]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[61]Ontario Power Generation, Bruce Power, "Ontario Power Generation and Bruce Power Complete Lease Agreement for Bruce Nuclear Stations", *News Release*, May 12, 2001.

[62]Sierra Club of Canada, "Bruce Deal a Disaster for Ontario", *News Release*, April 17, 2001.

[63]Ontario Power Generation, *Application by OPG & Bruce Power to amend the operating licences for the Class 1 nuclear facilities to include conditions on decommissioning plans and related financial guarantees*, CNSC CMD 03-H11.1A, April 10, 2003.

[64]Peter Calamai, "Nuclear cleanup to cost billions", *Toronto Star*, April 11, 2003, p. A6.

[65]Peter Calamai, "Nuclear panel gives Bruce Power reprieve", *Toronto Star*, September 13, 2002, pp. E1 & E11.

While the four Bruce B reactors continued to operate, reactor 2 at the Bruce A nuclear station was shut down in October 1995, and reactors 1, 3 and 4 were shut down in early 1998 because of technical problems and poor performance.

In November 2000, Bruce Power selected AECL as the general contractor to lead an internal "inspection and condition assessment" of 70 fuel channels[66] as well as steam generators for Bruce A reactors 3 and 4. The assessment cost $30 million and was intended to determine if the re-commissioning of the reactors was economically justified.[67] With the guaranteed profit from the Bruce B station through its lease agreement with OPG, there was little doubt that Bruce Power would have ready cash to proceed with the Bruce A restart project. On April 6, 2001, Bruce Power announced that it intended to restart reactors 3 and 4 at the Bruce A station. At that time, Bruce Power expected that the reactors would be restarted in the summer of 2003 at a total cost of about $340 million (CDN).[68] The schedule was subsequently speeded up to restart reactor 4 in April 2003, and reactor 3 shortly afterwards.[69] However, there were repeated problems and delays and reactor 4 did not start up until October 2003. Reactor 3 did not restart until February 2004. The cost of refurbishing the two reactors also more than doubled to $720 million.[70]

[66]There are 480 fuel channels in each Bruce A reactor, so AECL is making a safety judgement based on an examination of only 7% of the 960 channels in reactors 3 and 4.

[67]Bruce Power, "Bruce A Re-start Evaluation in the Works", *Open Line*, Issue 9, November 24, 2000. Http://www.brucepower.com/whatsnew/pdfs/Issue_9.pdf

[68]Bruce Power, "Bruce Power Forges Ahead on Bruce A Restart", *News Release*, April 6, 2001.

[69]Pearl Marshall, "Bruce Power said to be planning return of final Bruce A units", *Nucleonics Week*, October 24, 2003, pp. 1, 14-15.

[70]John Spears, "Nuclear power key to future: Bruce chief", *Toronto Star*, January 30, 2004, p. A4.

CANDU Fuel Channel Problems

Problems with fuel channels in CANDU reactors have historically been the single largest cause of outages at CANDU reactors. The 480 fuel channels in each Bruce reactor core are prone to age-related problems due to the weight of the fuel bundles, as well as high temperatures, pressures and radiation fields in the reactor cores. Fuel channels in CANDU reactors consist of an outer calandria tube, and an inner pressure tube. The inner pressure tube holds uranium fuel bundles, and heavy water coolant is pumped through at high pressure to draw off the heat released by the fission process. Pressure tube problems include 'creep' and 'sag', where the metal thins out over time and the tubes become wider and longer, bending under the strain. Various design changes were made in later stations to try to accommodate this problem, but eventual tube replacement ('retubing') is anticipated on a schedule dictated by the extent of the problem in each reactor core.

When the pressure tubes sag they can come into contact with the outer 'calandria tube'. This increases the chance of pressure tube rupture caused by 'embrittlement', where the metal becomes brittle due to absorption of hydrogen. This 'metal hydriding' process happens faster where the sagging pressure tubes make contact with the cooler calandria tubes. The space or annulus between the calandria and pressure tubes is maintained by spacers or 'garter springs'. However, at Bruce reactors 3 and 4 (as well as at Pickering reactors 5 and 6), the garter springs are not locked into place and have to be periodically checked and moved back into position to keep the two tubes from touching.

AECL has argued that pressure tubes will always leak before rupturing, allowing time to shut the reactor down before a loss of coolant accident occurs -- an assumption they call 'leak before break'. However, there have been at least two cases of catastrophic pressure tube ruptures in Ontario reactors: August 1983 at Pickering 2 and March 1986 at Bruce 2. All fuel channels at the Pickering A station reactors were subsequently replaced. Bruce reactors 1 and 2 will likely require complete retubing if they are ever to be restarted. Some individual tubes at Bruce reactors have been replaced in the past, but Bruce Power is taking a calculated risk, trading off safety against profit by arguing that complete replacement of fuel channels is not necessary at Bruce reactors 3 and 4. Bruce Power has taken this controversial position despite having inspected only 7% of tubes. Complete retubing of the reactors would likely more than double the estimated $720 million restart cost of reactors 3 and 4 as well as extending the outage time.

After the four Pickering A reactors, the Bruce A nuclear station has the oldest commercial reactors in Canada. In addition to pressure tube problems , there are other serious ongoing problems at Bruce. On June 11, 2002, an electrical arc burned a hole through a pressure tube and calandria tube during maintenance at Reactor 6 of the Bruce B station. This resulted in the reactor being shut down until early September. Bruce Power said only that a pressure tube had been "slightly damaged" and "the operational impact is not expected to be significant".[71] The incident was kept secret on the basis that public knowledge of the shutdown of the reactor would have commercial implications for British Energy. Because of concerns about nuclear safety and the public's right-to-know, secrecy about nuclear shutdowns has prompted public protest.[72]

[71]John Spears, "Shutdown hits Bruce reactor while Ontario had heat wave", *Toronto Star*, September 26, 2002, pp. A1 & A21.

[72]See: "Secrecy at Bruce", *Toronto Star Editorial*, September 27, 2002, p. A26.

Problems with steam generators have been the second largest cause of outages at CANDU reactors. All of the Bruce steam generators have been identified as being "high risk".[73] Past problems with steam generators have included clogging due to mineral deposits, 'fretting' or breakage of the internal pipes due to excessive vibration, and stress corrosion cracking of the metal. Steam generators incorporate thin-walled pipes where coolant from the reactor core circulates to transfer heat to the turbine side of the station. The steam generators at Bruce reactor 2 were damaged beyond repair after a lead shielding blanket was left inside the system during a maintenance procedure years earlier. Bruce reactor 2 was subsequently closed in 1995.

The Canadian Nuclear Safety Commission (CNSC) conducted a screening level environmental assessment on the restart of the Bruce A reactors 3 and 4. This was a low-level environmental assessment, and the CNSC maintained control over the process by ignoring public requests to ask the federal Environment Minister to appoint an independent assessment panel. As the "Responsible Authority" for federal nuclear matters, CNSC is in charge of all lower level environmental assessments (Screenings and Comprehensive Studies) unless it refers an assessment to the Minister of Environment for a hearing by an independent panel. A panel is more independent, since its members would be specially appointed by the Minister, and funding would be provided for intervenors.

On April 12, 2002, the CNSC approved the *Environmental Assessment Guidelines* for the screening assessment. Bruce Power issued its Environmental Study Assessment Report in August 2002, and CNSC released its screening report in October 2002.[74] On December 12, 2002, the CNSC held a hearing on the environmental assessment screening report for the return to service of Units 3 & 4 of the Bruce Nuclear Generating Station (NGS) 'A'. The Board ignored the concerns of environmental groups, and decided that the Screening Report had met all of the requirements of the Canadian Environmental Assessment Act.[75] Citizens for Renewable Energy (CFRE) and other groups had expressed concern about: the limited scope of the hearing; the CNSC's failure to request a bump up of the assessment to a full panel review; poor management of the assessment process; the need to expand the study area boundaries; delegation of technical environmental assessment studies to the proponent; and the failure of the CNSC to select a realistic range of severe accidents and malfunctions for consideration. The Chippewas of Nawash First Nation raised many concerns about the impacts of the reactor restart project on their fishing business near the nuclear plant.

[73]Ontario Hydro, Rick Machon, *Nuclear Asset Optimization Plan: Development & Recommendation*, "Option Selection Basis", p. 16.

[74]Canadian Nuclear Safety Commission, *Screening Report on Environmental Assessment of the Proposed Restart of Units 3 and 4 Bruce A Nuclear Generating Station, Kincardine, Ontario*, October 2002.

[75]CNSC, *Record of Proceedings, Including Reasons for Decision, In the Matter of Applicant: Bruce Power Inc,., Subject: "Environmental Assessment Screening Report for the Return to Service of Units 3 & 4 of the Bruce Nuclear Generating Station (NGS) 'A'", January 6, 2003*.

On January 6, 2003, the CNSC allowed Bruce Power to load fuel into reactors three and four in advance of the actual reactor start-up, delegating actual approval to CNSC staff without any need for a public hearing review.[76]

Bruce Power has also announced that it is conducing a feasibility study on the restart of the Bruce A reactors 1 and 2.[77] As part of its feasibility study, Bruce Power is also looking at a major refurbishment of the Bruce B reactors. In the absence of a large-scale refurbishment project, this study estimates that Bruce B will be forced to shut down after 25 years of operation, i.e. between 2010 and 2012 (see Table 2). The Bruce Power feasibility study and a corporate decision on these matters are expected before the end of 2004.[78] Because reactors 1 and 2 are in far worse shape than reactors 3 and 4, it is expected that the cost of their refurbishment could be more than double the $720 million cost of restarting reactors 3 and 4. This study estimates a range of $1.5 to $2.5 billion as the possible cost of the refurbishment project (see Table 6).

Bruce Power has also raised the possibility of building one or two new reactors that have yet to be designed by Atomic Energy of Canada Limited, known as the Advanced CANDU Reactor (ACR). Construction of a demonstration reactor for an untested design would be extremely risky. Bruce Power has undoubtedly been buoyed by windfall profits under its agreement with the Government of Ontario. In 2003, Bruce Power's profit increased to $286 million, compared to $106 million in 2002.[79]

Following a financial crisis at British Energy in the fall of 2002, it was announced on December 24, 2002, that a new Canadian group would purchase Bruce Power. The group consisted of Cameco Corporation, TransCanada Pipelines Ltd., and BPC Generation Income Trust, part of the OMERS pension fund. The three major partners held 31.6%, while the Power Workers Union had 4% and the Society of Energy Professionals 1.2%.

4.3. The Estimated Costs of Nuclear Refurbishment

Refurbishment of nuclear plants can involve a wide range of potential work, but in CANDU reactors, the most serious aspect of refurbishment is replacement of all the fuel channels in the reactor (see above: "CANDU Fuel Channel Problems"). This is known a Large Scale Fuel Channel Replacement (LSFCR), and has been characterized as 'heart transplant' for a CANDU reactor -- essentially the reactor core is re-built, requiring an extended outage of at least two years for the plant, at an extremely high cost.

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[76]CNSC, *Record of Proceedings, Including Reasons for Decision, In the Matter of Applicant: Bruce Power Inc,., Subject: "Referral to a CNSC Designated Officer - Application to load fuel at Bruce 'A' NGS unit 3 and 4 reactors", January 6, 2003*.

[77]Bruce Power, "Bruce Power to explore restart of Bruce A Units 1 and 2", *News Release*, January 29, 2004.

[78]"Bruce Power Ponders Additional Nuke Restarts", *Electricity Daily*, February 6, 2004.

[79]John Spears, "Bruce Power profit more than doubles; idle reactors powered up", *Toronto Star*, January 24, 2004, p. C3.

Table 6.
Estimated Refurbishment Costs for Ontario Nuclear Power Plants
(Current Dollars)

Station	Cost Range
Bruce 3 & 4	$720 million*
Bruce 1 & 2	$1.5 to $2.5 billion
Pickering A	$3 to $4 billion
Pickering B	$3 to $4 billion
Bruce B	$3 to $4 billion
Darlington	$3 to $4 billion
Total	$14.2 to $19.2 billion
Midpoint	$16.7 billion

*Actual cost. Source: John Spears, "Nuclear power key to future: Bruce chief", *Toronto Star*, January 30, 2004, p. A4.

This study estimates that the cost of refurbishment for all 20 Ontario Power Generation Reactors will be in the range of $14.2 billion to $19.2 billion, with a midpoint of $16.7 billion (see Table 6). This assumes complete fuel channel replacement of all reactors except for Pickering A (which was already re-tubed 1983-1993) and Bruce reactors 3 and 4. This is consistent with other recent estimates of refurbishment costs. Torrie Smith Associates has suggested that the cost of refurbishing OPG's nuclear fleet would be "...on the order of $15 to $20 billion...".[80] The Pickering "A" review Panel has suggested that the total cost of refurbishing all four reactors and common systems at the Pickering A station ranges from $3 to $4 billion. This range is based on figures prepared by OPG for financial modeling purposes.[81]

The low end of the cost range ($14.2 billion) assumes that there will be no major surprises, and the high end of the range ($19.2 billion) assumes that there will be some significant additions to the estimated costs. Every nuclear power plant built by Ontario Hydro had significant cost overruns. This history demonstrates that there is severe economic risk in nuclear construction projects because of their technological complexity and high capital costs.

The cost estimates in Table 6 are conservative insofar as they do not make allowance for a number of significant hidden costs...

- There is major uncertainty about how long the reactors will continue to operate after refurbishment has taken place. For example, Pickering reactor 4 was shut down in 1997 less than 5 years after undergoing a complete fuel channel

[80]Ralph Torrie and Richard Parfett, Torrie Smith Associates, *Phasing out Nuclear Power in Canada: Toward Sustainable Electricity Futures*, Campaign for Nuclear Phaseout, July 2003, p. ii.

[81]Pickering Review Panel, *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 4.

replacement. OPG has refused to say how long the refurbished Pickering A reactors should last.

- Replacement power costs are a major expense for the utility during the extended outages required for refurbishment (at least 18 to 20 months per reactor). This is typically not included as a cost of refurbishment.

- Nuclear utilities generally assume that plants will have excellent performance after refurbishment, for example 89% capacity factor in the case of the Point Lepreau refurbishment proposal (see below). By contrast, the capacity factor of the Pickering A nuclear station in 1997 (the year before it was shut down for the second time) was about 54%, despite having been retubed 1983-1993.

- The labour costs of utility staff working on the refurbishment project may not be counted as part of overall costs since 'they are on staff already'.

There have been several reports of refurbishment costs, but Ontario Hydro/OPG has made no rigorous reporting available to the general public, so these figures must be understood as approximate at best. The Pickering A station was retubed 1983 to 1993, following the disastrous 1983 pressure tube rupture in reactor 2. However, Ontario Hydro never provided an accurate accounting of the cost of that massive refurbishment exercise. In 1988, Hydro stated that...

> The cost of retubing units 1 and 2 [at Pickering "A"] cost $450 million (dollars of the year, 1984-1988) and work on the last two units is expected to cost about $500 million in dollars of the year, 1989-1993.[82]

As noted above, the cost of the Pickering A restart was estimated in 1999 at $780 million for all 4 reactors.[83] However, by September 2002, Ontario Power Generation reported that costs for the project had escalated to $1.025 billion.[84] At that time, OPG estimated that the start-up of Reactor 4 would cost another $230 million, and the other three reactors would cost an additional $300 to $400 million each.[85] Thus the cost for restarting reactor 4 alone was then estimated to be $1.255 billion, with a likely additional $1.2 billion for the other three reactors, totaling $2.455 billion -- three times the original cost estimate.

The OPG Review Committee confirmed on March 18, 2004, that the cost of the restart of Pickering reactor 4 had escalated to $1.25 billion at the time of its restart in October 2003. The Committee estimated that the cost of restarting reactor 1 would be $775 to $925 million, of which $325 million has already been spent.[86] It is not clear whether this $325 million is

[82]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p. 2.

[83]KPMG, *Ontario Power Generation Inc. Financial Review of Operations*, March 15 2004, p. 20.

[84]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002, p. 12.

[85]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002.

[86]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 51.

included in the $1.25 billion cost of reactor 4 or is in addition to it. The Committee also failed to provide any estimate of the cost of restarting reactors 2 and 3.

As we have seen above, the reported cost of the refurbishment of Bruce reactors 3 and 4 is $720 million.[87] It is not clear, however, what this cost includes. It has been suggested that the cost of refurbishing Bruce reactors 1 and 2 might be twice the cost of reactors 3 and 4. This study accepts that estimate as the low end of the range for their refurbishment.

4.4. Regulatory Opposition to Point Lepreau Refurbishment

The most publicly studied example of a proposed nuclear refurbishment project is the Point Lepreau Nuclear Generating Station. It is a single "CANDU 6" reactor (635 MWe) that began commercial operation in February 1983. The plant is owned and operated by New Brunswick Power, and was designed by AECL. Like other reactors of the period, the Point Lepreau plant was intended to run for 40 years, however, after less than twenty years, the reactor experienced serious performance and safety problems. In 1998, an NB Power consultant decided that the plant would require total replacement of all 380 fuel channels in the 2006-2008 period.[88] This schedule , however, has already slipped. According to the retube and refurbishment schedule, the work would take almost 5 years, and the plant would be shut down for 18 months.[89] The total estimated cost of the project was $845 million.[90]

On January 8, 2002, New Brunswick Power filed an application to the New Brunswick Board of Commissioners of Public Utilities (known as the Public Utilities Board or PUB) to hold a public hearing on the refurbishment of the Point Lepreau nuclear generating station. The hearing began on May 27, 2002, with final arguments in June. The PUB released its decision on September 24, 2002, noting that its review was made from an economic perspective, but with a public interest viewpoint. The decision was a stunning rejection of AECL's refurbishment proposal as put forward by NB Power...

> The Board, as a result of its review of the evidence in relation to the capacity factor and the cost of capital, finds that there is no significant economic advantage to the proposed refurbishment project. In addition, the Board considers that there are other significant aspects of the refurbishment option for which the economic impact is uncertain. These aspects create additional economic risk which leads the Board to conclude that the refurbishment of Point Lepreau, as outlined in the evidence, is not in the public interest. The Board, therefore, will

[87]John Spears, "Nuclear power key to future: Bruce chief", *Toronto Star*, January 30, 2004, p. A4.

[88]New Brunswick Power, *Road to Refurbishment at Point Lepreau Generating Station*, April 2001.

[89]NB Power, *Project Execution Plan*, Appendix A-4, February 2002, Table 4-1, p. 17.

[90]NB Power, *Project Execution Plan*, Appendix A-4, February 2002, Table 1-1. p. 1. This includes an 'overnight' cost of $633 million with escalation and interest during construction of $211million.

recommend to the Board of Directors of NB Power that it not proceed with the refurbishment of Point Lepreau.[91]

- The PUB rejected many of the basic assumptions underlying the agreements of the proposed contractor, Atomic Energy of Canada Limited (AECL), and NB Power. The following are some of the conclusions reached by the PUB...an 80% capacity factor should be assumed for the refurbished plant instead of 89% as proposed by AECL and NB Power; [92]
- a discount rate of 9.33% should be used instead of 7.15% for the cost of capital for the project; [93]

(N.B. These two adjustments alone make the cost of Point Lepreau refurbishment approximately equal to the cost of a new natural gas-fired generating plant [94])

- the stipulated liquidated damages payable by AECL may not be sufficient; [95]
- there is a significant risk from delay of the project (a four-month delay would increase the cost by $63 million plus $5 million per month in interest charges.); [96] and

- there is a "regulatory risk" that the federal regulator, the Canadian Nuclear Safety Commission, may require significant changes to the refurbishment plan as proposed.[97]

The PUB decision was only a recommendation to the Board of Directors of NB Power, and it is not clear at this time, whether the refurbishment proposal will proceed despite the PUB decision. NB Power has attempted unsuccessfully to find a purchaser or equity partners for Point Lepreau.

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[91] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 16.

[92] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 5.

[93] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 6.

[94] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 6.

[95] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 8.

[96] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 10.

[97] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 13.

Figure 1
Ontario Nuclear Capacity
(Actual 1971-2003, Projected 2004-2019

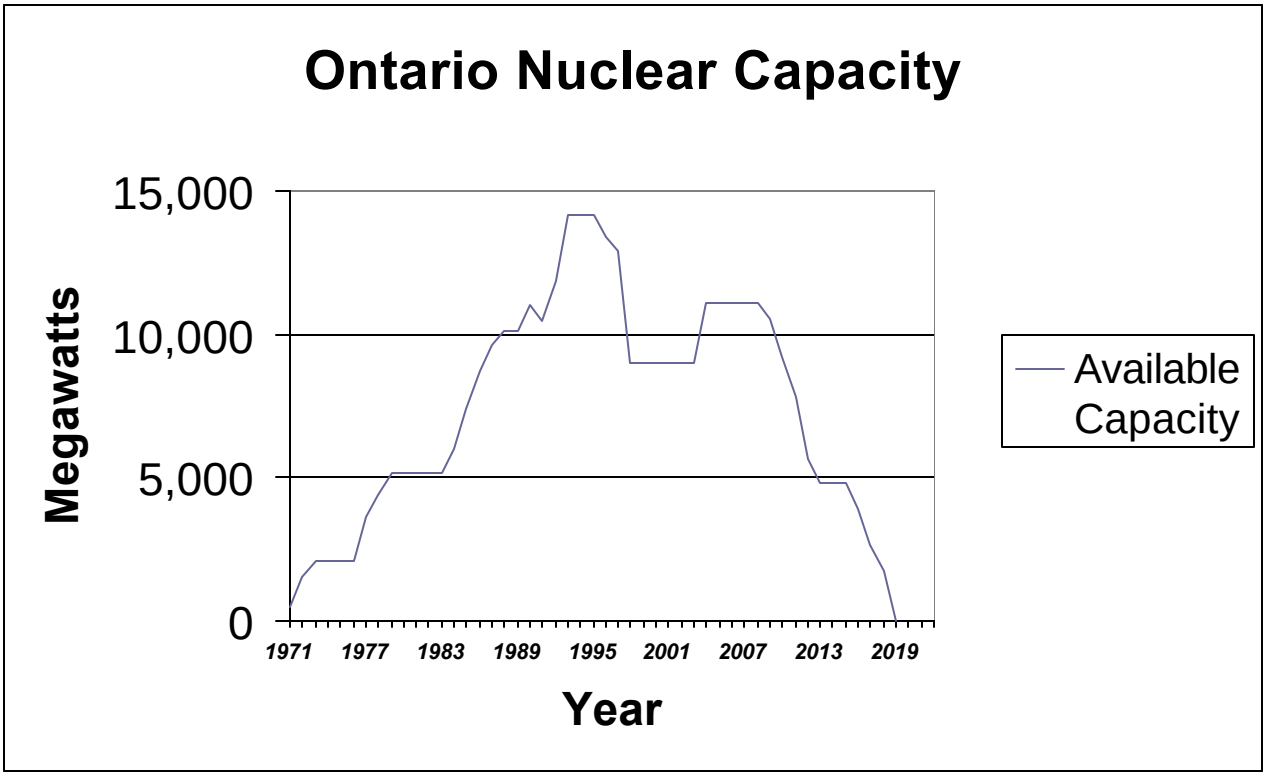


Figure 2
Lifetime Performance Vs. Age for Ontario Nuclear Power Plants

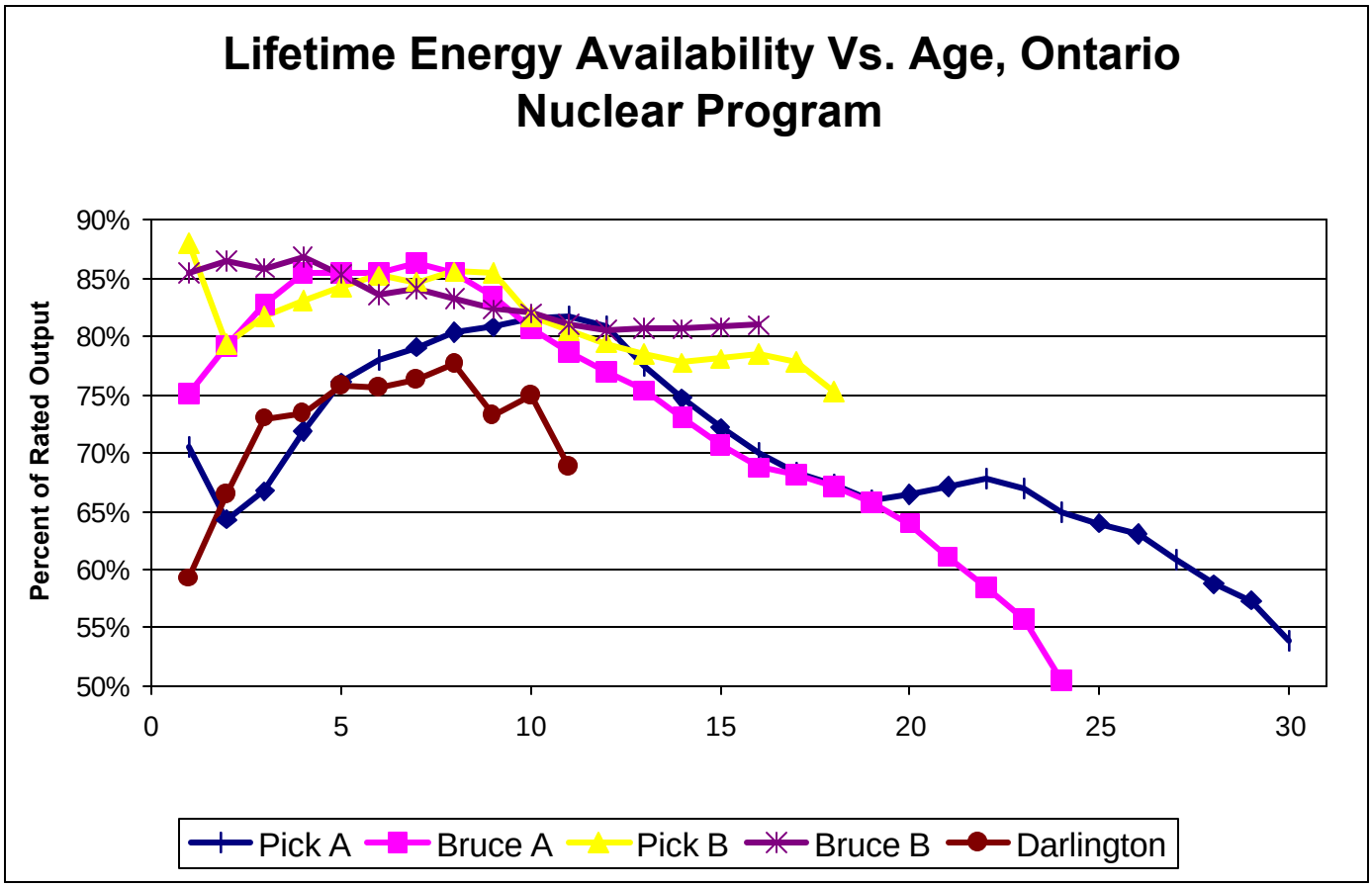


Figure 3
Average Cumulative Availability Vs. Reactor Age for Ontario Nuclear Program

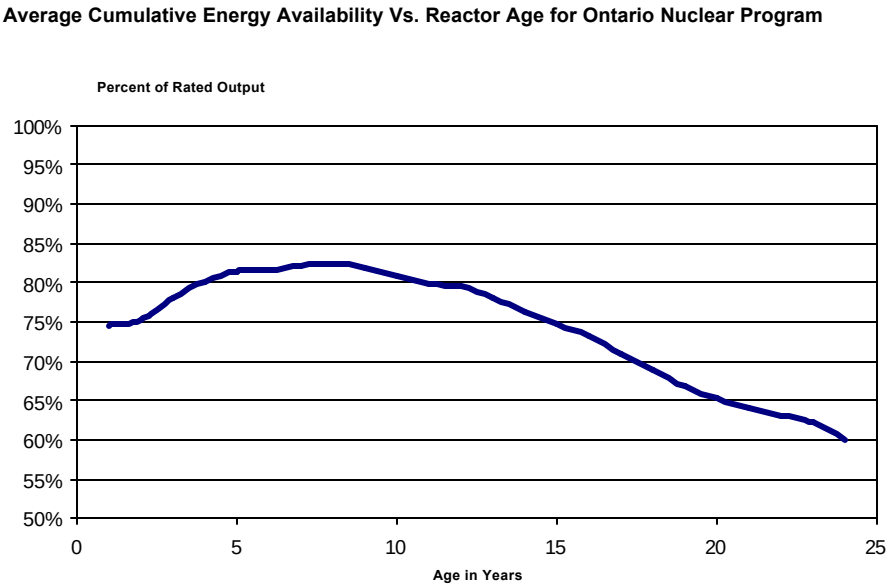
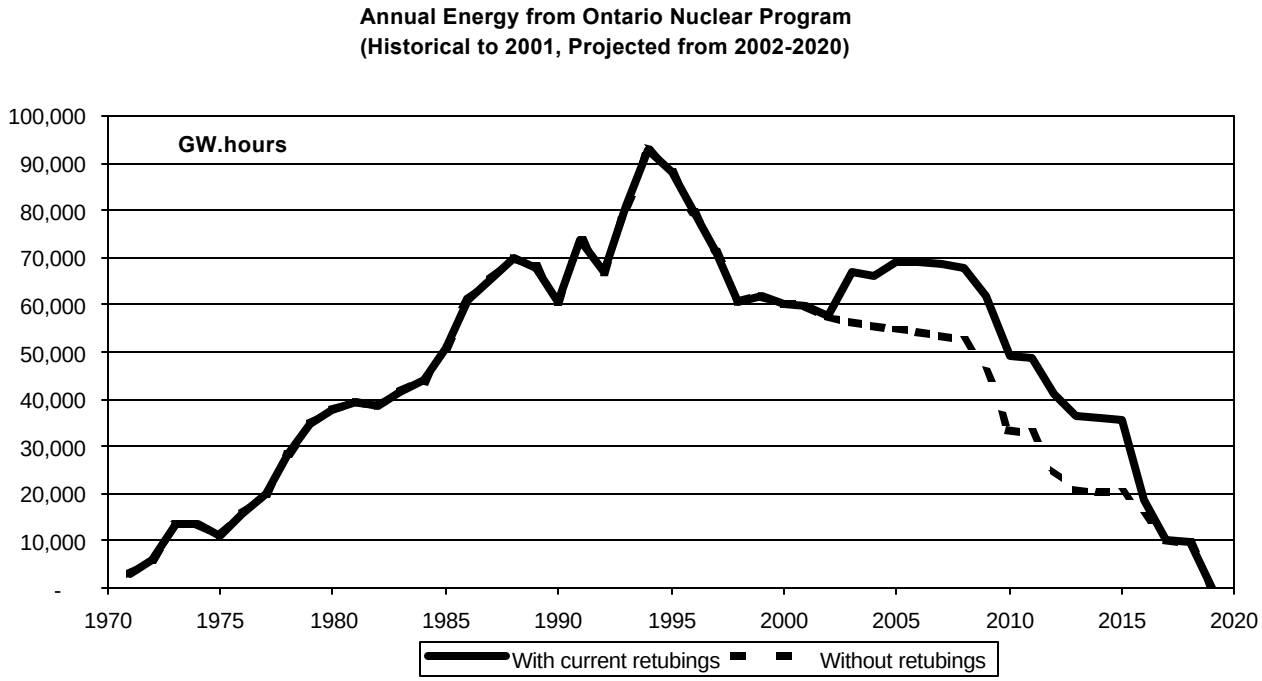


Figure 4
Annual Energy from Ontario Nuclear Program
(Actual 1971-2001, Projected 2002-2020)



Appendix 3
Energy Efficiency Program Case Studies

Appendix 3: Energy Efficiency Program Case Studies

The following program types are highlighted in this Appendix:

1. Residential Energy Efficiency Renovation Programs
2. Residential New Home Programs
3. EnergyStar Technologies Promotion and Financing Programs
4. Building Operator Training Programs
5. Commercial and Institutional Building Retrofit Programs
6. Commercial and Institutional New Building Programs
7. Multi-Purpose Efficiency Programs

A series of case studies are provided under each category, offering information on the financial, and energy saving performance of relevant established energy efficiency programs in North America.

1 Residential Energy Efficiency Renovation Programs

Case Study 1 – EnerGuide for Houses and ATCO Energy Sense

This program offers home evaluations that will assist in planning renovations, reducing drafts and increasing comfort, proper ventilation, reduce heating and cooling costs, assessing building plans, buying a house, and providing an energy efficiency rating. It provides homeowners with the facts they need to make informed decisions about energy efficiency. It applies to Canadian homeowners. This program was recently launched in Alberta through ATCO Energy Sense. It provides home energy audits for $150/home, while the Natural Resources Canada (NRCan) Office of Energy Efficiency (OEE) provides an incentive of more than $150/house to ATCO. Program participation figures for Alberta are unavailable. In the Yukon, since May 1999, more than 200 Yukon households have participated in the EnerGuide for Homes program[1].

Case Study 2 – Yukon Home Repair Program

The Yukon Housing Corporation offers low-interest loans of up to $35,000 to carry out home repairs. These are 10-year loans at a 1.9% interest rate. Additional subsidies are available for low-income families. The goal of the program is to improve the housing stock in the Yukon. Energy efficiency has been identified as one of the program's objectives. In the 2001/2002 fiscal year, 157 homeowners participated, of which 85% (133) included energy efficiency repairs. Since 1995, the Home Repair Program has assisted with improvements for over 350 Yukon households.

In the period of January through June 2001 there were 183 applications which is three times higher than the same period for the previous year. This was likely due to high energy prices at the end of 2000 and the lowering of program interest rate to half of the average 5-year bank mortgage rate.

The 2001/2002 Budget was $3.24 million with $2.862 million directed to loans. In the previous year, $1.247 million was expended.

Homeowners are responsible for implementing the actual repairs. The program requires a technical inspection before and after repairs to identify eligible repairs to get house up to current standards. Upgrades can include doors, windows, insulation, furnaces and water heater. Houses that are five years of age and older are eligible. The program will begin to use the NRCan EnerGuide auditing system for inspections in the future[2].

[1] References: EnerGuide for Houses contact person: Barbara Mullally-Pauly (613) 995-2945, Office of Energy Efficiency website: oee.nrcan.gc.ca/english/programs/index.cfm, EnerGuide website: oee.nrcan.gc.ca/energuide/home.cfm, ATCO EnergySense website: www.atcoenergysense.com, Yukon Energy Solutions Centre website: www.nrgsc.yk.ca

[2] References: Marc Perreault (867-393-7154) and Don Routledge (867-667-5759), Yukon Housing Corporation and Yukon Energy Solutions Centre website: http://www.nrgsc.yk.ca

Case Study 3 – Old Crow Yukon Contractor Energy Efficiency Training Initiative

The Pembina Institute implemented a project in Old Crow, Yukon in collaboration with the Yukon Housing Corporation and the Vuntut Gwitchin First Nation (VGFN) Housing Department to provide technical training for local trades people to carry out a series of renovations on residential homes that were targeted through an energy efficiency program. Funding for identifying the energy efficiency options was provided by Devon Energy Canada (formerly Anderson Exploration), while funds for training were provided by Yukon Housing Corporation and Natural Resources Canada.

A detailed four-day training workshop was delivered in the community in late April, 2002. It encompassed the following topics:

- Overview of the R-2000 housing program
- Building Science and Indoor Air Quality
- Overview of the R-2000 Building Envelope Standard
- Overview of mechanical systems – heating and domestic hot water
- Overview of mechanical systems – ventilation
- Examination of participants' learnings
- Hands on experience at the VGFN Safe House construction site

15 individuals from the community participated in the training program and 13 of them wrote and passed the exam, including several builders, the housing manager and other interested parties. As a result of the initiative, Old Crow currently has a large number of skilled energy efficiency practitioners that can proceed with housing renovations that meet high energy efficiency standards.

Case Study 4 – Massachusetts In-Home Services Program

This program aims to improve the energy efficiency of existing homes through retrofit programs (there is another program to build new homes that are 15% more energy-efficient than conventional homes). This program demonstrates effective partnerships between the Department of Energy Resources and electric utilities. Each utility offers a distinctive program and also offers consumer incentives.

The NStar Residential Conservation Service Program has energy efficiency specialists determining eligibility for a Home Energy Assessment. The assessment includes an analysis of home's energy use, advice for saving energy, and rebate offers on recommended energy improvements[3].

Massachusetts Electric Company's "Mass-Save" program offers a free home energy analysis to residential customers and installs low-cost energy and water-saving materials. They provide a report detailing the energy-saving recommendations identified by the energy advisor. For larger buildings, a Multi-family Building Audit is also available. They also sell energy efficient light bulbs at a discount[4].

[3] See http://www.nstaronline.com/index2.asp?lk=home
[4] See http://www.masselectric.com/res/conserv/index.htm

Case Study 5 – PowerSmart Home Information Program

Power Smart is a BC Hydro demand side management program that has invested $600 million over the last 10 years. The residential sector activities include a website and targeted initiatives in select "Power Smart Communities" including the Comox Valley, Quesnel, and all of Vancouver Island. These programs are smaller that initiatives in the early 1990's across British Columbia.

PowerSmart has budgeted $70 million for residential and commercial sector programs during the period 2003-2005. As part of the residential programs in Comox Valley and Quesnel, BC Hydro gave away over 40,000 energy saving light bulbs to community residents and picked up and recycled over 500 second refrigerators. The energy savings from the two programs combined have avoided emitting up to 1,250 tonnes of greenhouse gases into the atmosphere per year. These and several other programs helped residents save energy and money while positively impacting the environment. Other programs include access to home energy efficiency audits, and incentives for energy efficiency improvements made by certified contractors[5].

The Power Smart website for homeowners includes the following components:

- A Home Energy Profiling tool to find out what areas homeowners can target to reduce their energy consumption.
- An Appliance Calculator that calculates how much energy each homeowner's appliances use.
- Power Smart Tips, which provides advice on how to save energy around the house.
- An Energy Library, which is a comprehensive resource full of, detailed information on heating, water, lighting, appliances and more.
- A Shop Power Smart site that highlights those home products that are Power Smart certified and where to buy them.
- A section on Power Smart Homes that indicates which new housing developments have Power Smart certification and general advice on how to include maximum energy efficiency in home renovation plans.

[5] See http://www.bchydro.com/powersmart/ and article: "Power Smart re-launched on the Island" by Darrell Bellaart, Nanaimo News Bulletin, 7 October 2002.

2 Residential New Home Programs

Case Study 1 – Yukon Green Mortgage

The Yukon Housing Corporation Green Mortgage Program encourages building or upgrading houses to meet a high standard of energy efficiency and indoor air quality as specified by the Green Home Certification standard. It offers residential mortgages with a preferred interest rate for green homes. Once a new or existing dwelling is certified as a Green Home, the purchaser and subsequent purchasers are eligible to apply for a Green Mortgage with a preferred interest rate. The rates on Monday, January 13, 2003 were (prime rate was 4.5%):

- 3.880% for a 1 year term
- 4.580 2 yr
- 4.980 3 yr or 4yr
- 5.230 5yr

The Green Mortgage program offers a minimum down payment of 5%, no mortgage insurance fee (i.e., worth up to 4.25% of the mortgage), 1,2,3,4, and 5 year term options, a maximum borrowing amount of $200,000, and interest rate reduction based on the average interest rates posted at local banks.

Any revenues from the Green Mortgage are directed into the "Senior's Housing Fund" which will help address future housing needs of Yukon Seniors. As such, it is a revolving fund that reinvests savings into further energy efficiency and housing improvements.

The basic Green Home criteria include the following:

- Specific design standards, primarily based on the R-2000 criteria
- 75% of building materials
-
-
- n business
- Acceptable EnerGuide rating, including a pressure test

As of 2001, 17 certified Yukon Green Homes have taken advantage of the Green Mortgage Program. The program involves a partnership between contractors, the federal government (R-2000 program), local materials suppliers, and homeowners[6]. One shortcoming of the program is that it is taking mortgages away from private banks.

[6] See http://www.nrgsc.yk.ca/programs/yukon_energy_programs.php#Yukon_Housing_Programs or contact Heather Doucet. 867-667-8784 (heather.doucet@gov.yk.ca)

Case Study 2 – Texas Housing Partnership Program

This program aims to improve energy efficiency in low to moderate income housing through the establishment of partnerships among non-profit organizations, community action agencies, local governments, utility companies, public housing authorities, and social service-related organizations. The program encourages community and residential involvement in energy efficiency projects such as housing retrofits, model demonstration projects, technical training assistance, and energy education workshops and seminars. The program is a partnership between the State Energy Conservation Office (SECO) and various other bodies.

The Housing Partnership Program has 3 sub-programs.

1. Energy Efficient Housing Demonstration Project: Encourages community and residential involvement in energy efficiency projects such as housing retrofits, model demonstration projects, technical training assistance, and energy education workshops and seminars. Through a competitive bid process, several projects have demonstrated the cost-effective use of energy efficiency in residential housing since 1997. Many of the project activities and results can be replicated across Texas. The projects cover a range of activities:
    - Energy efficient design and building methods
    - Metering/monitoring of household energy consumption
    - Builder/homeowner training
    - Energy efficient appliances
    - Passive solar design/measures

2. Housing Trust Fund Program: SECO is partnering with the Texas Department of Housing and Community Affairs' Housing Trust Fund Program to increase the energy efficiency of new and existing multi- and single-family housing for low income persons and families. The Housing Trust Fund Program is the only state-authorized program dedicated to the development of affordable housing, and provides loan funds to finance, acquire, rehabilitate, and develop affordable housing for low income persons and families. SECO will provide funds to ensure that energy efficient design and appliances are incorporated in the new construction. The SECO funding will be through grants that require the housing construction to exceed a minimum standard[7].

3. Rebuild Texas - Rebuild Texas is a partnership of Rebuild America – a program sponsored by the U.S. Department of Energy (DOE) to help communities improve energy efficiency in commercial and multifamily buildings. SECO has two initiatives under this partnership:
    - Public Housing Energy Efficiency. SECO has helped develop a series of training workshops, to pass on the technical expertise from the DOE's Oak Ridge National Laboratory to promote buildings that are more energy efficient. The workshop topics range from performance contracting to local contracting; from

[7] Council of American Building Officials Model Energy Code (CABO MEC) '92 and '95.

maintenance and upkeep to resident education; and from no-cost/low-cost measures to major rehabilitation projects.

- Texas Showcase Communities. SECO is establishing partnerships to improve energy efficiency in cities which have populations ranging from 10,000 to 35,000. The aim is to implement a wide range of energy efficiency measures in local government buildings, schools, hospitals, small commercial buildings, farms and housing. The saving achieved in the local community through these measures will be used to provide additional improvements in the communities.

This program is run by the State Government agency SECO[8]. However, many programs in Texas are run by utilities following the 1999 Senate Bill 7 which restructured the state electric utilities and required each investor-owned utility to meet at least 10% of the utility's annual growth in demand through cost-effective energy efficiency measures. Most programs were offered full-scale in 2002[9].

[8] See http://www.seco.cpa.state.tx.us/Hp.htm and http://www.seco.cpa.state.tx.us/hp_eef.htm
[9] See http://www.aceee.org/new/texas.pdf

3 EnergyStar Technologies Promotion and Financing Programs

Case Study 1 – Ontario Sales Tax Exemption (8%)

All Energy Star appliances are to exempt from provincial sales tax (8%) under the new Bill 210, "Electricity Pricing, Conservation and Supply Act, 2002". Anecdotal evidence has shown this has been a great success, partly because consumers love to save taxes.

Case Study 2 – BC Hydro PowerSmart EnergyStar Promotion

This program aims to encourage the transformation of the appliance market in British Columbia to Energy Star products using incentives for retail sales staff. BC Hydro's Power Smart "product designation" program for products that either improve electricity efficiency (e.g., weather stripping) or have high efficiency (e.g., certain electric water heaters) has been extended to include promotion of the Energy Star labeling of refrigerators, clothes washers, and dishwashers.

There are several components to the promotion:

- Pilot projects to provide financial incentives to retail sales staff to sell Energy Star appliances – the sales person receives a bonus of $20 for each Energy Star appliance sold.
- Providing information on Energy Star on the Power Smart web site and in promotion of Power Smart products.
- Listing of all retailers in BC that carry Energy Star appliances on web site.
- Pilot projects to provide incentives to consumers to buy Energy Star appliances when an old refrigerator is removed from the home at the same time.

The pilot staff incentive program targeted a small number of retail stores. It ran for 12 months and the results show that although it has resulted in good awareness building for Energy Star among sales staff, it has not helped sales. The normal mark-up on appliances is so large that $20 is no real incentive for selective selling – maximizing volume is.

Annual energy savings for each appliance have been estimated below based on differences in performance between typical Energy Star and conventional appliances:

- Energy Star refrigerators use about 50% less electricity than a typical 10-year-old fridge and at least 10% less than the minimum federal standard.
- Energy Star clothes washers use 35-50% less hot water than a conventional washer.
- Energy Star dishwashers use 25% less electricity than the minimum federal standard.

The pilot program was run in partnership with the NRCan OEE and certain major retailers. The estimated cost of the pilot by OEE was $137,000[10]. Actual energy savings are not available.

[10] Reference: OEE 2002/2003 Business Plan

BC Hydro has had better success with consumer incentives – especially on compact fluorescent lights. The buy-one-get-one-free promotion has worked well and is liked by suppliers.

Case Study 3 – SaskEnergy High Efficiency Furnace Loans

This program aims to promote gas heating furnaces and appliances and achieve energy savings by accelerating the replacement of old heating systems with a new ones. Retailers also gain from selling and installing the new equipment.

The program is delivered through the Sask Energy Natural Gas Network – a group of independent equipment retailers and contractors across Saskatchewan. Prime interest rate loans are offered on the following new gas heating appliances:

- Furnaces
- Water Heaters
- Radiant Heaters
- Unit Heaters
- Space Heaters
- Boilers
- Fireplaces
- Clothes Dryers

The program offers a six month deferred payment option, a fixed loan rate at the prime rate (currently about 4.5%), a maximum loan per customer of $10,000, and a maximum loan period of 5 years. The program started in July 1, 2001 and has recently been extended to June 2003. Loans are arranged through local financial institutions with Sask Power paying the difference in loan interest.

No preferences are currently given for energy efficiency. The reasons given are that 1) until Energy Star there has been no simple definition of high efficiency, and 2) some rural members of the Network were not able to service condensing furnaces. However, Sask Energy plans to promote the selection of Energy Star furnaces and water heaters under the program in the spring of 2003, in cooperation with the NRCan OEE as part of their national strategy to promote Energy Star. No decision has been made yet to limit the loans to Energy Star only.

All residential and small business customers in Saskatchewan are eligible. As of December 2002, 5,882 residents had participated in the program with approved loan value of $19.8 million. The target for each year was 2,500 customers. Operating costs are estimated at $800,000 per year.

The program is operated by the Sask Energy Marketing and Sales Department and funds are allocated through the marketing budget. Sask Energy provided training and

information to the members of the Network and made arrangements with financial institutions to provide the loans[11].

Case Study 4 – California Appliance Recycling Program

The Statewide Residential Retrofit Program includes an Appliance Recycling provision. The objective of the program is to encourage the removal of operable but inefficient appliances (i.e., refrigerator, freezer). In addition, the program includes a focus on second refrigerators within homes, so does not necessarily involve replacement.

Target Audience and Participation

The program had a target of removing 34,800 units in 2002, at an estimated cost of US $200 per unit. This target was exceeded in the summer of 2000, when two utility companies retired and recycled 37,000 working inefficient refrigerators and freezers.

Program Management

The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by 3 major utility companies. Each utility plan may vary in terms of the number of units they propose to recycle, the budgets and consumer incentive structure. However, in 2002 companies were required to target and obtain a certain proportion of hard-to-reach customers. Companies are required to offer comprehensive toxic material recycling and disposal in accordance with California environmental laws.

Budget and Funding

The statewide program budget was nearly US $7 million for 2002, of which $6.7 million was for delivery and the remainder was for evaluation, monitoring, etc. Consumers were offered either a $35 rebate per refrigerator/freezer that was removed, or a five-pack of compact fluorescent light bulbs, worth $50.[12,13,14] The program is offered on a first come, first served basis, depending on the budget.
The program is one of many that is funded by Public Purposes Charge. This is a direct tax on electricity and natural gas that is used to fund energy efficiency programs. The charge was introduced at the same time as deregulation, to ensure the continuation of energy efficiency measures. The charge appears as part of the monthly utility bill (both electricity and natural gas). It is approximately US 0.37 cents per kWh for electricity (or

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[11] Reference: Sask Energy Web site and Sask Energy Marketing staff. NRCan OEE staff.
[12] California Public Utilities Commission, 2002. *Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs,* IV Programs Selected. Website at: http://www.cpuc.ca.gov/published/final_decision/14345-03.htm
[13] Originally the rebate was US$50. See Pacific Gas and Electric, Statewide Residential Appliance Recycling Program, Program Report October 1 to December 31, 2002, p.2. Website at: http://www.pge.com/003_save_energy/003a_res/cempe/pdf/4q02_recycling_narrative.pdf
[14] The energy efficient lamp bulbs have a retail value of $50, which provides an incentive for customers to choose the light bulb option, rather than the money, see Southern California Edison, Refrigerator and Freezer Recycling Program. Website at: http://www.sce.com/sc3/011_reb_off/011a_fyh/011a1_reb_off/011a1b_ref/011a1b2_ref_frez.htm

between 2 and 3%, though the actual amount varies, depending on the sector and company).[15]

Energy Savings

In 2002 the CPUC targeted a reduction of 72.9 million kWh per year and a reduction of overall demand by 11MW for the three utility companies[16].

To assess the actual achievements of the program, one needs to look at the reports of the individual utility companies. Southern California Edison had an initial budget of US$4 million, which resulted in 19,916 units being recycled (actual and committed), for a net saving of 34.4 million kWh and 5.5MW capacity.[17] Before the end of the year, additional funds were added which will allow a further 4512 units to be recycled, with additional energy and demand savings of 7,782 MWh and 1.2 MW.

At the end of the year, Pacific Gas and Electricity (PGE) reported spending its full budget of US$1.68 million and that additional funds were shifted to the program, increasing the total budget to US2.5 million. When the fourth quarter report was compiled, the company had recycled 10,193 appliances (actual and committed), for an energy saving of 17.4 million kWh and saving of 2.7 MW capacity.[18,19] These are preliminary figures and do not appear to account for the full, enlarged budget. The company will update the figures in their 2003 report. At the time the report was compiled only US$1.83 million of the budget had actually been spent. At PGE the energy efficient light bulbs were chosen rather than the financial rebate in exchange for more that half the appliances recycled (5460 chose light bulbs, compared with a total 10,193 appliances). As a result of the uptake of the lamp bulbs additional energy savings of 249,000 kWh were achieved (that is, 1.6% more than the program target).

Because final figures are not available, it is not possible to report the total savings accomplished in 2002.

Financial Characteristics for Consumers

The consumer would pay for a replacement appliance, where required, but could offset the cost by $35 received for recycling the old appliance.

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[15] California Energy Commission, 2003. California Investor-Owned Utilities Retail Electricity Price Outlook 2003-2013, see also http://www.energy.ca.gov/energypolicy/documents/index.html

[16] Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs, California Public Utilities Commission. IV Programs Selected. http://www.cpuc.ca.gov/published/final_decision/14345-03.htm

[17] Southern California Edison, Residential Appliance Recycling Program, October 1, 2002 thru December 31, 2002, p. 1 and 2. Website at: http://www.sce.com/NR/rdonlyres/eq27aqkd5wzpd2lt5vklnox2otzdhdlijw6mvmuybjzket4z2iienubq3tgbil4gofrxsoex4l3jj644hip37rv7iwc/EE_Filings_4Qtr_2002_Report.pdf,

[18] Pacific Gas and Electric, Statewide Residential Appliance Recycling Program, Program Report October 1 to December 31, 2002. Website at: http://www.pge.com/003_save_energy/003a_res/cempe/pdf/4q02_recycling_narrative.pdf

[19] Full details about the program implemented by Pacific Gas and Electric are available in a workbook at http://www.pge.com/003_save_energy/003a_res/cempe/xls/4q02_recycling_wkbk.xls N.B. This report may be removed from the website at the end of the first quarter, 2003.

Implementation Issues

One of the utility companies (PGE) informed the public about the refrigerator/freezer recycling through a cable TV bill insert, that was sent by direct mail to over 6 million homes in the third quarter of 2002. In addition they supplied 25,000 point-of-sale fliers to appliance retailers, issued a press release and did 30 second cable TV ads.[20]

PGE note that customers received their incentive cheques within 10 business days of pick up.

Case Study 5 – California Upstream Residential Lighting Program

The objective of this program is to continue the upstream lighting program and, in 2002 to broaden the availability of EnergyStar qualified lighting products to include lighting fixtures, ceiling fans and other lighting measures in more stores and outlets. Retailers or manufacturers receive additional incentives that are passed on to the customer. The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by individual utilities. The program will also target the "hard to reach" through the addition of non-traditional delivery channels, such as grocery stores, drug stores, etc. The total program budget for 2002 was $9.3 million. The program's energy reduction targets for the 2002 program were 293 GWh of energy savings per year and a demand reduction of 23 MW[21].

[20] This was reported in the third quarter report for the program. However, this report is no longer available on the website, since it has been replaced with the fourth quarter report.

[21] Reference: Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs, California Public Utilities Commission. IV Programs Selected. http://www.cpuc.ca.gov/published/final_decision/14345-03.htm

4 Commercial Building Operator Training/Certification Programs

Case Study 1 – Northwest Energy Efficiency Alliance Building Operator Certification

The Regional Building Operator Certification (BOC) program aims to achieve energy efficiency through improved building operations. BOC is a professional development program that teaches facility managers, building operators, maintenance personal and others who monitor commercial building controls how to reduce energy and resource consumption in the facilities they operate. Building operators and managers who successfully complete a training series earn certification.

Studies show that electricity use in Northwest commercial and government buildings could be cut by 15 percent or more if building operators managed and maintained their structures and building systems more effectively. The program was initiated by the Northwest Energy Efficiency Alliance (NEEA) and is delivered by industry through a voluntary, competency-based certification process.

Almost 1000 students have participated since 1997, with about 250 per year. The program has trained over 10% of eligible participants. A target of 40% of operators has been made for 2010.

The program operates through a partnership between facility-oriented associations (e.g., Northwest Building Operators Association - NWBOA, Washington Association of Maintenance and Operations Administrators, Oregon Schools Facility Management Association, Operating Engineers Union, International Facility Managers Association), utilities and trade associations, and major employers in the Northwest (e.g., Boeing, U.S. Navy, Washington State Department of General Administration, University of Oregon). They develop an agreement on marketing and training responsibility through the Northwest Energy Efficiency Council in Oregon and Washington and NWBOA in Idaho and Montana.

The annual program costs include US$1.8 million for delivery, $140,000 for administration, and $233,000 for evaluation. The NEEA gets its funding from ratepayer sources sponsored by the Bonneville Power Association. They charged on average $966 per student between 1997 and 2000. The cumulative computed impact for the period 1997-2000 per student participating in the program was estimated to be 177,500 kWh (compared with an initial planning value of 25,000 kWh per year). Total annual energy savings of the whole program were estimated at 172 GWh at the end of the period between 1997 and 2000. A demand reduction of 19 MW was estimated to be achieved by 2001. The program demonstrated a benefit-cost ratio of 7.8[22].

[22] See http://www.nwalliance.org/projects/projectdetail.asp?PID=41 and http://www.nwalliance.org/resources/reports/88.pdf

5 Commercial and Institutional Retrofit Programs

Case Study 1 – NRCan OEE Energy Innovators Program

The Energy Innovators Initiative is designed to facilitate large-scale energy retrofit projects by providing funding of up to 25% of eligible costs to a maximum of $250k. Projects are selected on a competitive basis. The program will also subsidize study and feasibility costs. It requires that client commit to very strict and extensive process requirements. It unofficially relies on ESCOs to generate projects. It will pay up to $15/GJ of energy savings through funding provided by the federal government through the NRCan OEE. It is managed through an independent office[23].

Case Study 2 – New York Standard Performance Contracting Program

The New York State Energy Research and Development Authority (NYSERDA) offers a commercial and industrial performance program which aims to encourage contractors to implement cost-effective electrical efficiency improvements or summer demand reductions for eligible customers. This performance-based program offers incentive payments to contractors and ESCOs that develop projects delivering verifiable annual electric energy savings. Eligible measures include lighting (e.g., LED traffic signals and exit signs), motors, variable-speed drives, energy management systems, certain process equipment, packaged air conditioning devices and chillers (e.g., including non-electric refrigeration and chillers), and custom measures that result in electric-energy savings or demand reductions.

This program is open to facility owners or tenants who agree to pay the New York State System Benefits Charge for the duration of the standard performance contract (SPC) agreement. All classes of customers (i.e., commercial, industrial, and residential) that meet program requirements are eligible. Eligible customers are electricity distribution (i.e., default) customers of Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation. The performance-based incentives are provided through an SPC between NYSERDA and the contractor. The contract between the customer and the contractor can be an energy performance contract or a fee-for-service contract. The average annual electric energy savings will be verified for up to a two-year period following project installation. There is a customer cap of $1 million and a contractor cap of $4 million. Documented Nitrogen Oxide (NOx) emission reductions achieved by energy efficiency projects receiving incentive funds are eligible to receive additional incentives.

Energy marketers are encouraged to participate and offer energy efficiency as a value-added service. There are two stages: project planning/installation which occurs prior to and just after installation of the energy efficiency measures; and project measurement and verification activities which occur after the energy-efficient equipment is installed and operating. The NYSERDA reviews profile information provided by the ESCO to determine if the measure is cost effective on a resource cost basis. Cost effective measures with long lives and higher energy and demand savings produce higher cumulative present value of savings and will receive higher incentive rates. Photovoltaics, and other renewable technologies, are sometimes eligible for

[23] See http://oee.nrcan.gc.ca/eii

incentives. The maximum incentive for custom measures is capped at 30 percent of its cost. The total contracted project incentive paid to an ESCO may not exceed 50% of the total project cost[24].

Cumulative funding for the program to date has been US$81 million. As of September, 2002, $33.5 million was spent. Funding for June 2002 to June 2003 period is $20 million on first come, first served basis. As of June 2002, a total of 405 projects were in various stages of completion, from project development to measurement and verification. Incentives of more than $70 million were awarded to 93 ESCOs.

As of September, 2002, annual savings of 232 GWh and a demand reduction of 51 MW were achieved. When fully implemented in 5 years, the projects are expected to reduce electricity use by 489 GWh per year, including a reduction of the summer peak demand by more than over 100 megawatts[25].

Case Study 3 – New York Energy Efficiency Services Technical Assistance

This program is a part of the New York State Energy Research and Development Authority's (NYSERDA) Business and Institutional Program. The program provides technical assistance in the following areas:

- Energy feasibility studies – to identify capital improvements
- Energy operations management – to improve electrical energy efficiency of facility operations
- Rate analysis and aggregation – to prepare customers to negotiate energy prices and services with independent marketers

Businesses, not-for-profit and private institutions, state and local governments, schools, universities, multi-family buildings, health-care facilities, and building owners are all eligible. Customers can select their own consultants or use one of NYSERDA's 36 pre-selected firms to provide help through the Flexible Technical Assistance program, which offers the same services as the standard Technical Assistance program.

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[24] The total contracted project incentive is the sum of the energy efficiency incentive, and any small site bonus, electric chiller and A/C bonus, and NOx incentives, included in the SPC Agreement. The total contracted project incentive also includes any demand reduction incentive approved for a custom demand reduction measure. The total contracted project incentive paid to an ESCO may not exceed 50% of the total project cost. If a project includes a custom conversion measure, the incentive will be capped at 30% of the measure cost. For these purposes, total project cost includes all costs directly associated with the energy savings of the project including, but not limited to: the Detailed Energy Analysis; energy efficiency measure design, procurement and installation; measurement and verification of energy savings (where the ESCO is responsible for M&V); and ESCO overhead and profit. Where a project includes more than one customer, the 50% limit applies to each customer individually See section 3.2 Total Project Incentive at: http://www.nyserda.org/695pon.html

[25] See http://www.nyserda.org/695pon.html and http://www.nyserda.org/sbcsept2002.pdf Technical questions should be directed to Todd Baldyga at (518) 862-1090, ext. 3354 or tab@nyserda.org Contractual questions should be directed to Mary Sauvie at (518) 862-1090, ext. 3229 or mks@nyserda.org

Up to US$100,000 of funding is available per project for cost-shared help from energy engineers and experts. The total budget is $24.6 million of which $6.7 million has already been spent.

According to a survey of NYSERDA's clients, two-thirds of them have implemented recommendations made by Technical Assistance contractors. Each dollar spent on engineering services has resulted in $14 in capital improvements and $4 per year in energy savings. Savings of 195.5 GWh have been achieved, with a demand reduction of 52 MW. The program is targeting annual savings of 560 GWh and a demand reduction of 149 MW[26].

Case Study 4 – Texas LoanSTAR Revolving Loan Fund

This revolving loan fund was legislatively mandated to be funded at a minimum of US$95 million at all times. It aims to provide financing for energy efficiency projects to institutions of higher education, school districts, non-profit hospitals and local governments. Projects can include energy efficient lighting systems; high efficiency heating, ventilation and air conditioning systems; computerized energy management control systems; boiler efficiency improvements; energy recovery systems; and building shell improvements.

127 loans have been made to public institutions since the program started in 1989 with low interest rates that depend on money market costs and administrative costs. For the year ending August 2002, the rate was 3%. The fund is managed by the State Energy Conservation Office (SECO). Texas A&M University is responsible for monitoring and verifying the energy savings.

Between 1989 and the end of 2000, the program had achieved annual energy savings of $100 million. The program has a 20-year target of $500 million of annual energy savings. Actual energy savings have exceeded targeted savings by 5% on average[27]. The maximum load repayment period is 10 years and the fund has already revolved one complete cycle.

SECO also has a State Agency Program which provides a provision for higher education, state agencies, public school districts and local governments to enter into performance contracting agreements, under which facilities make no upfront investments but finance projects through guaranteed annual energy savings[28].

Case Study 5 – VanCity Community Foundation

The VanCity Community Foundation is a catalyst for community transformation based on social and economic justice in a sustainable environment. It supports community partners to connect their current activity to transformation.

The Foundation provides the following services:

- grants of $2,500 to $15,000
- guaranteed loans and lines of credit of $10,000 to $100,000
- low interest loans of $10,000 to $100,000

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[26] See http://www.aceee.org/new/eedb.htm and http://www.nyserda.org/techasst.html and http://www.nyserda.org/sbcsept2002.pdf . Contact for the Flex Tech program: Jillina Baxter at (518) 862-1090, ext. 3279; fax (518) 862-1091; jb1@nyserda.org

[27] See http://www.seco.cpa.state.tx.us/ls.html or contact theresa.sifuentes@cpa.state.tx.us

[28] See http://www.seco.cpa.state.tx.us/sa_performcontract.htm

- technical assistance in marketing and communications, budgeting, business plan development, strategic and operational planning, board governance and others

The VanCity Credit Union provides an annual donation to the Foundation. Gifts are also provides from other donors. The general endowment has grown to more than $7.3 million in 2002. Committed community supporters have also added capacity through permanent legacies in the form of Named Fund endowments. Named Funds can be created with a gift of $1,000. The Foundation also provides matching interest for a period of time on Funds, which meet the mandate of the Foundation's grants program. The total permanent endowments are now more than eleven million dollars.

The Foundation provides grants to organizations that are involved in the following community economic development categories including:

- affordable housing
- employment development
- non-profit enterprise

Total grants and loans approved in 2001-2002 were $415,963[29]. The Foundation provides a model for financing of community based projects and could be applied to energy efficiency measures in a different context.

Case Study 6 – California Express Efficiency Program

The Express Efficiency program pays rebates to distributors and small to medium sized nonresidential customers for equipping facilities with selected EE measures, including T8 and T5 lamps, electronic ballasts, lighting controls such as photocell controllers and occupancy sensors, compact fluorescent lamps, high-efficiency motors and HVAC measures. There is an emphasis on the hard-to-reach sectors. The California Public Utilities Commission (CPUC) sets out general requirements and approves or amends plans and budgets submitted by individual utilities. The program targets small to medium sized nonresidential customers. Customers must have monthly demand of less than 500 MW and annual gas usage of less than 250,000 therms (7.3 GWh).

The total budget for the program is US$23.8 million. The program target for 2002 was savings of 284 GWh of electricity per year and 82 GWh of thermal energy savings along with an electrical demand reduction of 56 MW[30].

Case Study 7 – California Standard Performance Contract Program

The Standard Performance Contract Program provides energy efficiency incentives for comprehensive retrofit projects for large and medium businesses. Small businesses can also participate if their measures do not qualify for the Express Efficiency program. The programs include lighting, but only as part of the overall project. These programs are also coordinated by CPUC and delivered by individual utilities. Any customer paying the gas or electricity "Public Goods Charge" would be eligible, even if the customers have opted to purchase their gas or electricity from suppliers other than the default utility. The program involves a partnership between energy service companies who sponsor energy efficiency retrofit projects at utility customers' facilities. The utility companies provide general promotion and program information to customers.

[29] Reference: Vancity Community Foundation Annual Report 2001-2002
[30] Reference: CPUC (2002).

The program's budget was $20.7 million in 2002, of which $20.1 million for program delivery. The program has achieved savings of 73 GWh of electricity per year and 50 GWh of thermal energy savings along with an electrical demand reduction of 13 MW[31].

Case Study 8 – Massachusetts Commercial and Institution Retrofits

This program aims to improve the energy efficiency of commercial and institutional buildings through retrofit programs. The Massachusetts Division of Energy Resources (DOER) coordinates the program which involves a partnership with utilities which each have unique programs. In the year 2000 the budget for the program was US$53 million out of a total DOER budget for all energy efficiency programs of US$130 million. The benefit to cost ratio for this program and residential programs was 2.3, including post-program effects[32]. Program savings are expected at 122 million kWh per year.

The NStar utility program enables client to incorporate energy efficient lighting fixtures, controls, high-efficiency mechanical equipment, and other energy saving strategies within their current facility. Benefits of this program include: rebates up to 50% of the total project cost; cost sharing for engineering services; and design and commissioning services. NStar also has gas efficiency programs including: Small Business High-Efficiency Heating Rebate Program; Small Business High-Efficiency Water Heating Rebate Program; Infrared Heating Equipment Rebate Program; Building Operator Certification Training; and customized programs[33].

Massachusetts Electric Co. has several programs for large businesses. For small business they pay 80% of the cost of the installation of a company's energy saving improvements and finance the remaining 20%, interest free, for up to 24 months[34].

Case Study 9 – BC Hydro Power Smart Partners Program

The BC Hydro Power Smart Partners Program is designed to facilitate large scale electrical energy retrofit projects by funding electricity demand reductions on a competitive bid basis. It works with the 1000 largest electricity consumers in the province. The Bid "price" is determined by dividing funding requested by electrical energy saved. The program will also subsidize study and feasibility costs. The program reportedly has an unofficial price cap of 5 cents/kWh for savings. It is managed and funded by BC Hydro, but unofficially relies on energy service companies (ESCOs) to generate projects. Anecdotal evidence also suggests that program is overly complex for benefit realized, and may be replaced by a rate incentive program. The large required administrative and technical infrastructure is problematic[35].

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[31] Reference: CPUC (2002).
[32] See http://www.state.ma.us/doer/pub_info/ee00-long.pdf p.15
[33] See http://www.nstaronline.com/index2.asp?lk=buss
[34] See http://www.masselectric.com/bus/effic/index.htm
[35] See http://eww.bchydro.bc.ca

6 Commercial and Institutional New Building Programs

Case Study 1 – NRCan OEE Commercial Building Incentive Program

The Commercial Building Incentive Program (CBIP) pays an incentive to a building owner in proportion to the annual energy cost savings relative to a reference building roughly based on the Model National Energy Code for Buildings (MNECB). The maximum annual incentive is $60k per building. Savings must be demonstrated using software provided by the program. The objective of the program is to reduce energy consumption in new commercial construction. The program is financed and administered by NRCan's Office of Energy Efficiency using federal funds. The program is centrally managed by CBIP specific technical and administrative infrastructure. It has been in operation for 4 years. Energy and financial savings are unknown.

CBIP has already invested huge amounts in the setup and maintenance of the program. The CBIP budget unknown, but is clearly substantial. CBIP has experienced significant difficulties with all aspects of the program design and delivery. Major program revisions may be pending. However, it is likely to be an excellent fit for supporting Alberta programs because of the substantial financial investment to date in program infrastructure[36].

Case Study 2 – California Savings By Design

This program provides incentives for efficiency during the design process for non-residential buildings. This creates an incentive for designers to become engaged in energy efficiency. The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by individual utilities. CPUC has directed that at least 50% of funds be used for "whole-building" oriented projects. Building architects, design teams, building owners and developers receive incentives passed on the % by which the work exceeds the "Title 24 standards" (California's building energy standard). Building owners or designers receive an incentive if work exceeds 10% above the standard, while if the work exceeds standards by 15%, the architects and design team also receive an incentive.

The total budget for the program is $23.3 million per year, of which $22.5 million is for programs and the remainder is for monitoring and administration. The program savings goals approved by CPUC for 2002 were 87.6 GWh/year of electricity and 14 GWh of thermal energy along with an electrical demand reduction of 29MW[37].

Case Study 3 – New York State New Construction Program

This program aims to save energy in buildings by providing technical and financial incentives to applicants to specify and install selected energy-efficient equipment or to erect buildings that exceed the energy efficiency of standard design practice as determined by NYSERDA and the minimum requirements of the New York State Energy Conservation Construction Code. It can also be used for substantial renovations of buildings.

Applicants may choose among incentives for pre-qualified equipment, custom measures or whole building capital costs. The program provides technical assistance incentives to applicants to assist in the evaluation of energy-saving options for each qualified project and

[36] See http://cbip.nrcan.gc.ca/cbip. Further information is available from the Manager, Pierre Geuvrement, 613-996-6722, pgeuvrem@nrcan.gc.ca.
[37] Reference: CPUC (2002).

capital cost incentives to defray a portion of the incremental capital cost to purchase and install more energy-efficient or advanced equipment. The program may cover up to 80% of the incremental costs of qualified energy-efficiency measures. All energy-efficiency measures must meet cost-effectiveness and benefit/cost criteria set by NYSERDA.

The cumulative budget of US$64 million to date will deliver anticipated savings of 238 GWh and a demand reduction of 38MW. $28 million is available for projects during the period of June 2002 to December 2003 on a first come, first served basis, with $3 million allocated to building-integrated photovoltaics.

The process starts through an application to NYSERDA which has retained several Outreach Project Consultants (OPCs) to assist applicants. These OPCs work directly with program applicants to determine eligibility, explore participation options, identify technical assistance needs, and assist in completing program applications. NYSERDA provides written pre-approval of all qualified applications for incentives under this program. This pre-approval authorizes the applicant to proceed with the purchase and installation of the specific equipment and building features outlined in the approved application. Upon completion of the approved installation, the applicant is asked to provide written certification that the equipment and building features have been installed. NYSERDA may elect to inspect any or all projects prior to final approval. All building projects with approved incentive offers over $50,000 are inspected prior to payment[38].

[38] See http://www.nyserda.org/593pon.html and http://www.nyserda.org/sbcsept2002.pdf .
Questions can be directed to Cullen O'Brien at (518) 862-1090, ext. 3414 or cmo@nyserda.org

7 Multi-Purpose Efficiency Programs

Texas Standard Offer and Market Transformation Programs

The 1999 Texas State Senate Bill 7 requires that utilities to acquire energy-efficiency savings equal to the equivalent of at least 10% of their growth in demand. The Texas Public Utility Commission (PUC) oversees the implementation. A preliminary evaluation of programs was undertaken for the "Emission Reduction Incentive Grants Report" which was prepared for the Texas Natural Resource Conservation Commission in September 2002. As most energy efficiency programs were new in 2002, there is not a lot of analysis yet on their performance.

Utilities are to obtain the required energy savings by selecting programs in the following categories:

Standard Offer Programs	Market Transformation Programs
Commercial and Industrial	Air Conditioning Distributor
Industrial and Small Commercial	Energy Star Homes
Load Management	Residential Energy Star Windows
Hard to Reach	Air Conditioning Installer Information and Training

These programs apply to all sectors. They aim to maximize synergies with federal programs such as EnergyStar. Programs are managed by utilities.

The budget in 2002 was US$43.8 million, according to the utility reports to the PUC. Funding comes through transmission and distribution rates that are collected by utilities in areas where retail competition has begun and through electric rates in areas where competition has not begun. Energy savings of 246 GWh per year have been achieved. By 2007 it is estimated that the program will facilitate 510 GWh/year savings.

California Energy Efficiency Programs

California energy efficiency programs are controlled by the California Public Utilities Commission (CPUC). The following table highlights the various programs that are currently offered, some of which are explained in more detail in previous sections of this report. The table highlights energy and demand reduction targets for each program and program budgets[39].

[39] See http://www.cpuc.ca.gov/published/final_decision/14345.htm

Table 3.1 – California Energy Efficiency Programs

Program	Energy Reduction Target (GWh/yr)	Demand Reduction Target (MW)	Gas demand Reduction Target (GWh/yr)	Total Budget (US$ million)
Statewide Residential Retrofit Programs				
Home EE surveys				2.1
Appliance Recycling	72	11	88	6.7
Single-Family Unit Rebates for EE Equipment	47	33	88	24.5
Multi Family EE rebates	17	7	59	8.3
Statewide Residential New Construction	9	13	12	14.0
Statewide Nonresidential Retrofit Programs				
Nonresidential SPC Programs	73	13	50	20.1
Efficiency Express Programs	283	55	82	23.1
Nonresidential Audit Programs				7.1
Building Operator Certification and Training				1.0
Emerging Technologies				1.6
Statewide Nonresidential New Construction Programs	87	29	15	22.5
Marketing and Outreach Programs				10.0
Education and Training				7.3
Codes and Standards Advocacy				2.0
Statewide Upstream Residential Lighting Program	293	23		9.3
Total				$160

Appendix 4
A Comparison of Combustion Technologies for Electricity Generation

Appendix: A Comparison of Combustion Technologies for Electricity Generation

This appendix provides additional background information to the summary entitled "Best Available Pollution Control Technologies for Coal Combustion" that accompanies a Pembina Institute media release on July 24, 2001.

With commercially available coal-fired technology, it is possible to reduce emissions to levels considerably below those required by the Alberta government. In fact, some of the proven technologies reviewed in this document can achieve much better performance than the new Alberta standards demand; most are commonly used in jurisdictions in the U.S. and Europe and are economically viable at today's prices for natural gas, electricity and coal. Consequently, the Pembina Institute believes that proponents of new or retrofitted coal-fired plants in Alberta should be required to implement options that have better environmental performance than what is specified in the latest, already outdated, Alberta regulations.

1. Overview of Technologies

All coal combustion technologies rely on the generation of high pressure steam using heat produced by burning coal. This high pressure steam then drives a turbine, and electricity is produced from an electrical generator attached to the steam turbine.

Exhaust gases from combustion of the coal are typically cleaned by a series of downstream processes. Particulates are removed by electrostatic precipitators or fabric filters (baghouses), and sulphur oxides (SO_x) are removed by one of a range of possible flue gas desulphurization (FGD) processes. Nitrogen oxide (NO_x) production can be controlled by in-furnace features such as low NO_x burners. A Selective Catalytic or Non-Catalytic Reduction process can further reduce NO_x emissions.

The combustion of coal in the boiler can be accomplished in various ways, described below. In general, the most energy-efficient plants have the lowest emissions, as they produce more electricity per unit of coal burned. However, emissions from less-efficient plants can be reduced with "add-on" pollution control options.

1.1 Subcritical and Supercritical Pulverized Coal Combustion (PCC)

Coal combustion has traditionally occurred at atmospheric pressure using subcritical steam, but today, greater efficiencies can be obtained by using higher steam pressures in the supercritical range.[*] Both the subcritical and supercritical processes begin with coal being ground into a fine powder. The powdered coal is blown with air into the boiler through a series of burner nozzles where combustion takes place at temperatures from 1300-1700°C, depending largely on the coal type. Combustion occurs at near-atmospheric pressure, which simplifies the burner and coal handling facilities. Subcritical PCC plants use steam in the range of 16 megapascals (MPa) pressure and 550 °C while supercritical PCC plants use steam with pressures as high as 30 MPa and 600 °C. The higher steam pressure in supercritical plants results in higher energy efficiency – 38-45%, compared with 33% for subcritical plants. While supercritical plants have higher capital costs and some added risk due to the higher pressure and temperature, they have been in commercial use for many years.

[*] At atmospheric pressure, water bubbles at boiling point before turning into steam; above a certain critical pressure, it enters a "supercritical" state, where it undergoes a continuous transformation directly into steam.

Most plants in Alberta currently use only low efficiency subcritical coal-fired processes. If conventional pulverized coal combustion is being considered, proponents should use supercritical steam processes to maximize efficiencies.

1.2 Atmospheric and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used with high sulphur coal. In a FBC plant, hot air blown up through the floor of the boiler suspends or "fluidizes" powdered coal mixed with a sorbent such as powdered limestone. The combustion of the coal in the presence of the sorbent facilitates the capture of sulphur dioxide (SO_2). Conventional boilers, by contrast, simply burn the fuel on a grate in the firebox. FBC plants can remove up to 98% of the SO_2 and the coal burns more efficiently because it stays longer in the combustion chamber.

AFBC plants operate at atmospheric pressure, and NO_x generation is minimized due to lower combustion temperatures (815-875°C) than in conventional PCC plants. In contrast to AFBC plants, PFBC plants operate at elevated pressures. PFBC plants are typically more compact than similar capacity AFBC and PCC plants due to the higher pressure. The PFBC design allows for potentially greater efficiency, reduced operating costs and less waste than the AFBC design. PFBC plants use the same process as AFBC plants to fluidize or float the coal/sorbent mixtures. In both AFBC and PFBC plants, the reacted sorbent forms a dry, granular material that is easily disposed of or used as a commercial by-product. The reacted sorbent is removed with the bed ash through the bottom of the boiler and with the fly ash that has been collected in the dust collectors at the top of the boiler stacks.

In PFBC plants, additional energy is captured when the combustion gases that leave the fluidized bed are cleaned in a gas cleanup system and then re-burned in a gas turbine. The gas turbine is connected to an electrical generator thereby improving the plant's efficiency. The use of a steam turbine and a gas turbine improves performance by creating a highly efficient combined cycle system.

The operating temperatures of fluidized beds are between 760 and 870°C, approximately half the temperature of a conventional boiler. This relatively low temperature is below the threshold where thermally induced NO_x forms. Thus, the fluidized bed designs have reduced SO_2 and NO_X emissions when compared with PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels.

Given that most coal in Alberta has a low sulphur content (less than 1% and sometimes as low as 0.2%, compared with high sulphur coal, which contains up to 5%), it is unlikely that this process would be selected in Alberta.

1.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants are extremely clean and more efficient than traditional coal-fired systems. In IGCC plants, coal is not burned in a traditional boiler but is converted into a hydrocarbon vapour (syngas) in a gasifier. The syngas is then cleaned, stripped of impurities and used as fuel instead of natural gas in a conventional combined cycle plant (see description of the natural gas combined cycle plant, below). The result is an integrated gasification combined-cycle configuration that provides ultra-low pollution levels and high system efficiencies. The IGCC systems that are operating commercially have demonstrated exceptional environmental

performance. Emissions of SO_2 and NO_x are less than one-tenth of those allowed under U.S. New Source Performance Standards limits. Moreover, IGCC efficiency levels can be as high as 45%.

Most of the existing IGCC plants were built on a demonstration basis with government subsidies; however, these plants are nearing full commercial operation. For example, it is reported that the Wabash River plant in Indiana had an overall reliability of 79% in 1999 and operators are now receiving a lot of interest in their technology. A mechanism is in place for repayment of loans received from the Department of the Environment.

1.4 Comparison with Natural Gas Combined Cycle

The natural gas combined cycle process (NGCC) is not a coal combustion process, but a description is included here for comparison with the various coal-fired options

Commercial-grade natural gas burns more cleanly than other fossil fuels because it consists mostly of methane and has already been cleaned of sulphur. In NGCC plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the hot exhaust gas from the turbine is used to generate steam in a waste heat recovery unit. The steam is then used to produce more electricity in the same way as described for the PCC options above. The output from both the gas turbine and the steam turbine electrical generators is combined to produce electricity very efficiently. NO_x control in gas turbines is proven technology and can be accomplished with relatively low cost "low NO_x burners." In addition, NO_x can be reduced still further with such "add-on" control technology as Selective Catalytic Reduction (see below). Emissions of particulate matter are also quite low, although some secondary particulate matter is produced through atmospheric chemistry reactions involving NO_x.

A variation of the NGCC is the natural gas combined heat and power cycle (NGHPC). In these plants, the waste heat recovered from the turbine exhaust gas is not used to produce steam; instead, it is used to supply heat to an adjacent facility, such as a refinery. The end result is a plant that produces both electricity and useful heat. NGHPC plants have even higher overall energy efficiencies than NGCC plants, at lower capital costs, due to the elimination of the steam cycle. Several NGHCC systems are being used in oil, gas and petrochemical industries across Canada.

2. Add-on Pollution Control Options

A number of pollution control devices are commonly added onto conventional coal-fired plants. These add-ons can enable conventional coal-fired plants to achieve very low levels of emissions and, for some pollutants, the add-on options can result in coal-fired electrical generation being nearly as clean as natural gas-fired generation.

Flue Gas Desulphurization (FGD) – FGD is a process where lime or lime-like material is added to the flue gas to absorb sulphur compounds and reduce the amount of SO_2 emissions. The process can be wet or dry, regenerable or non-regenerable. Often the recovered sulphur or reacted absorbent can be sold as an industrial process chemical. Wet FGD systems can achieve up to 95% sulphur removal, while dry systems can remove up to 70-80% of the sulphur.

Low NOx Burners (LNBs) – Low NO_x burners are used to control the combustion process to minimize the formation of NO_x. The design of LNBs for gas turbines is well proven and NO_x reduction from LNB-equipped gas turbines exceeds 90%. This level of reduction meets many of the more stringent NO_x regulations in the U.S. and Europe; however, further reductions in NO_x

can be achieved with an SCR unit added to the exhaust of a gas turbine. LNBs for sub and supercritical PCC plants is also well proven but NO_x reduction from LNB-equipped PCC plants is only 50%. This necessitates the use of additional NO_x control equipment such as selective catalytic reduction to enable PCC plants to meet the standards in many parts of the world (although not Alberta).

Selective Catalytic or Non-Catalytic Reduction (SCR or SNCR) – SCR or SNCR is a process that removes NO_x formed in the exhaust gases due to high combustion temperatures. SCR technology involves the injection of ammonia (NH_3) into the exhaust gas, which then passes through a catalyst bed where the ammonia and nitrogen oxides react to form harmless nitrogen and water vapour. SNCR involves a similar process but without the catalytic reaction. Both SCR and SNCR can reduce NO_x emissions by about 80% before ammonia slippage out of the exhaust stack becomes a problem. These technologies have been applied to both gas and coal-fired facilities to further reduce NO_x emissions.

Electrostatic Precipitators (ESPs) and Fabric Filters (Baghouses) – ESPs or baghouses are commonly added to all coal-fired power plants to remove particulate matter and flyash from the exhaust gases. ESPs use an electrostatic charge to attract small particles, whereas baghouses simply filter the particulate matter from exhaust gases using a self-cleaning fabric filter process. ESPs are more prone to upsets since they rely on an electrical charge, which is typically de-energized during a plant shutdown. Baghouses are less sensitive to upsets and are more efficient at removing most particulates. Both ESPs and baghouses are able to remove some mercury (that fraction of mercury emissions already associated with the flyash) if they are used on cooled exhaust gas. Baghouses are generally more efficient at removing mercury than ESPs.

3. Comparison of Coal Combustion Options

The following table compares coal combustion technologies. It summarizes the characteristics of the various coal-fired generating technologies and compares them with cleaner burning natural gas systems. Footnotes appear immediately following the table on page 8. All dollars are Canadian currency unless otherwise noted.

Coal Combustion Technology Comparison

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Environmental Performance [1]							
Plant Efficiency [2]	33%	38-43%	36%	42% [3]	45%	52%	~60%
Heat Rate (GJ/MWh)	10.9	9.5-8.4	10	8.6	8.0	6.9	6.0 per equiv. MWh
CO_2 (kg/MWh) [2]	1000	870-770	920	790	735	400	350
Sulphur Removal Standard	Alberta: 180 ng/J U.S.: 260 ng/J, 70-90% removal and BACT [4]						
SO_2 (kg/MWh) – no FGD	1.6 [5]	1.4 [6]	0.3 [7]	0.12 [3]	~ zero	~ zero	~ zero
SO_2 (ng/J) – no FGD	229	221	30 [8]	14	~ zero	~ zero	~ zero
S02 (ng/J) – w ith FGD	< 70	< 66	Not required	Not required	Not required	Not required	Not required
NO_x Removal Standard	Alberta: 125 ng/J U.S.: 65 ng/J						
NO_x (kg/MWh) – no SCR	2.1 [2]	1.8 [6]	0.5 [7, 8]	<0.7	0.25-0.45 [9] (w/ LNB)	0.12 (w/ LNB)	0.12 (w/ LNB)
NO_x (ng/J) – no SCR and w/ LNB	86-125 [5]	86-125 [5]	43	<86 [3]	31-56	18 [10]	18 [10]
NO_x (ng/J) – with SCR and LNB	43-62	43-62	SCR not required	SCR probably not required	SCR probably not required	SCR probably not required	SCR probably not required
Particulate Matter Standard	Alberta: 13 ng/J U.S.: 13 ng/J						
PM (kg/MWh) – no ESP/Baghouse	0.5	0.4 [6]	~0.4	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
PM (ng/J) – no ESP/Baghouse	46	42	~42	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
Mercury	Depends on coal source	Depends on coal source	Depends on coal source	Better than PCC but not as good as IGCC	Little or no air borne mercury	Little or no air borne mercury	Little or no air borne mercury

Base Processes	**Subcritical Pulverized Coal Combustion (PCC)**	**Supercritical PCC**	**Atmospheric Fluidized Bed Combustion (AFBC)**	**Pressurized Fluidized Bed Combustion (PFBC)**	**Integrated Gasification Combined Cycle (IGCC)**	**Natural Gas Combined Cycle (NGCC)**	**Natural Gas Combined Heat and Power Cycle**
Pollution Control Add-ons							
Flue Gas Desulphurization (FGD)	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	Not required	Not required	Not required	Not required	Not required
NO_x Control: Low NO_x Burners (LNB)	LNB can reduce approx. 50% NOx formation.	LNB can reduce approx. 50% NO_x formation.	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.
NO_x Control Selective Catalytic Reduction (SCR)	80% NO_x removal without ammonia slip problems. [12]	80% NO_x removal without ammonia slip problems. [12]	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.
	Note: Typically **both** LNB and SCR required in PCC plants to meet most standards.						
Baghouse or ESP	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Not Required	Not Required	Not Required
Mercury[13]	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse and FGD 60-70% removal. ESPs not as effective.	With baghouse up to 70% removal.	With baghouse up to 70% removal.	Not Required	Not Required	Not Required
CO_2 Capture	From flue gas, difficult to recover.	From flue gas, difficult to recover.	From flue gas, difficult to recover.	Recovery should be similar to IGCC.	Relative to other options, recovery is more straightforward from off-gas. [14]	From flue gas, difficult to recover.	From flue gas, difficult to recover.

Base Processes	**Subcritical Pulverized Coal Combustion (PCC)**	**Supercritical PCC**	**Atmospheric Fluidized Bed Combustion (AFBC)**	**Pressurized Fluidized Bed Combustion (PFBC)**	**Integrated Gasification Combined Cycle (IGCC)**	**Natural Gas Combined Cycle (NGCC)**	**Natural Gas Combined Heat and Power Cycle**
Operational Performance							
Currently in use at:	Genesee, Keephills, Wabamun. Many plants worldwide.	Europe, Japan, U.S. Many plants worldwide.	Pt. Aconi, NS uses Circulating Fluidized Bed (185 MW plant), first one in Canada 1993. [7] Japan, Europe. Commonly used with high sulphur coal.	Sweden, Spain, U.S., 350 MW plant under construction in Japan. [15] Commonly used with high sulphur coal.	General coal gasification well proven. IGCC used at three U.S. plants (Polk, Wabash,[16] Pinon Pine) and in The Netherlands and Spain.	Many plants worldwide.	Many plants worldwide.
Commercially Proven	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Scale	100-1000 MW	100-1000 MW	400 MW guaranteed by manufacturer. [8]	80 MW	100-300 MW	Any size in modulars	Any size in modulars
Reliability and Uptime	Good	Good	Good	Good	Good [16]	Good	Good
Economic Performance [17]							
Capital Cost – main process ($/kW)	$**1200**-1500 [15] $1283 [18] $1200 [19]	**$1275**-1575 [15] $1322 [18] $1200 [19]	$**1500**-1950 [15] $1324 [18]	$**1725**-2025 [15] $1429 [18]	$**1800**-2100 [15] $1798 [18] $1800 [20]	**$1,000**	**$940** [21]
Capital Cost – add-ons ($/kW)							
FGD	$**105**-180 [15] $158-236 [22]	$**105**-180 [15] $158-236 [22]	N/R	N/R	N/R	N/R	N/R
SCR [19]	$**60**-120	$**60**-120	N/R	N/R	N/R	N/R	N/R
LNB [19]	$**7.5**-15	$**7.5**-15	$**7.5**-15	$**7.5**-15	Std.	Std.	Std.
Total Capital Cost ($/kW)	**1373**	**1448**	**1508**	**1733**	**1800**	**1000**	**940**
(Sum of bold numbers above used in total capital cost)							
Return (%)	15%	15%	15%	15%	15%	15%	15%
Life (yrs)	35	35	35	35	35	35	35
Total Capital Cost ($/MWh)	23.68	24.97	26.01	29.89	31.06-34.94	17.25	16.22
(Note: No Tax, No Depreciation)							
Operating Cost ($/MWh)							
Labour [23]	2.08	2.08	2.32	2.77	2.77-3.12	2.08	2.08
Other (100% of labour)	2.08	2.08	2.32	2.77	2.77-3.12	1.63	2.08
Energy (GJ/MWh)	10.9	9.5	10	8.6	8.0	6.9	6
$/GJ [17 24 25]	**1.18**	**1.18**	**1.18**	**1.18**	**1.18**	**4.00**	**4.00**
Energy Cost ($/MWh)	12.86	11.21	11.80	10.15	9.44	27.60	24.00
Operating Cost – add ons ($/MWh)							
FGD [22]	2.6	2.6					
Total Operating ($/MWh)	19.62	17.97	16.44	15.69	14.98 - 15.67	31.31	28.16
Overall levelized cost to produce electricity ($/MWh)	**43.30**	**42.94**	**42.45**	**45.58**	**46.04-50.61**[26]	**48.56**	**44.38**

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Rank (1=Best, 7=Worst)							
Efficiency/GHG Ranking	**7**	**5**	**6**	**4**	**3**	**2**	**1**
Sulphur Removal Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
NO_x Control Ranking	**7**	**6**	**4**	**5**	**3**	**2**	**1**
PM Emission Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
Mercury Emission Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
CO_2 Sequestration Ranking	**More Difficult**	**More Difficult**	**More Difficult**	**Less Difficult**	**Less Difficult**	**More Difficult**	**More Difficult**
Capital Cost Ranking	**3**	**4**	**5**	**6**	**7**	**2**	**1**
Operating Cost Ranking	**5**	**4**	**3**	**2**	**1**	**7**	**6**
Overall Cost to Produce Ranking	**3**	**2**	**1**	**4**	**6**	**7**	**5**

Table Footnotes

[1] Environmental performance characteristics described are at the plant site only. These values do not consider any "upstream" impacts, such as from coal mining operations, natural gas production and processing.

[2] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations - Pulverized Coal Power Plant," http://www.ieagreen.org.uk/emis4.htm, 40% efficiency emits 830 kg/MWh and 43% efficiency emits 770 kg/MWh.

[3] Southern Illinois University, Coal Research Center, "Pressurized Fluidized Bed Combustion," www.siu.edu/~coalctr/presfbc.htm.

[4] Application of terms of the U.S. EPA standard would result in at least 70% removal of sulphur, or about twice what would be required with Alberta standards and Alberta's coal.

[5] From EPCOR's EIA for Genesee 3.

[6] Based on ratio of efficiencies (33% vs. 38%).

[7] See Nova Scotia Power's website: http://www.nspower.ca/OurEnvironment/EmissionControls/. Port Aconi Power Plant in Nova Scotia removes 90% of the sulphur and 60% of NO_x.

[8] Southern Illinois University, Coal Research Center, "Atmospheric Fluidized Bed Combustion," www.siu.edu/~coalctr/atmosfbc.htm.

[9] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Integrated Gasification Combined Cycle," http://www.ieagreen.org.uk/emis6.htm.

[10] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Natural Gas Combined Cycle," http://www.ieagreen.org.uk/emis5.htm based on 25 ppm (~ 18g/GJ).

[11] "Sorbent Injection Systems," www.siu.edu/%7ecoalctr/sorbinj.htm.

[12] Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," http://www.siu.edu/~coalctr/postcomb.htm.

[13] Environmental Working Group, Clean Air Network and Natural Resource Defense Council, "Mercury Falling: An Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington DC.

[14] CO_2 is recovered at the large gasification project at Great Plains, Dakota and injected into underground reservoirs for enhanced oil recovery at Weyburn, Saskatchewan. See Dakota Gasification Company website: http://www.dakotagas.com/ and http://ens.lycos.com/ens/jul2000/2000L-07-14-11.html.

[15] Energy Issues (The World Bank) No.14 August 1998, " Technologies for Reducing Emissions in Coal-Fired Power Plants" by Masaki Takahashi, http://www.worldbank.org/html/fpd/energy/enls14.pdf. Costs in $US converted to $Cdn at 1.50 exchange rate (1995$).
[16] Wabash River (one of the U.S. IGCC Demonstration Projects) has begun repaying the DOE and has also achieved 79% overall reliability in 1999, "Clean Coal Today" Newsletter of the Office of Fossil Energy, U.S. DOE, DOE/FE-0215P-39 Issue No. 39, Spring 2000.
[17] All currency in Canadian dollars.
[18] From EPCOR's EIA for Genesee 3, Vol.1, Figure 2.2.1.
[19] Calculation based on the average of Keephills and Genesee 3 expansions.
[20] This number represents the actual cost of constructing the greenfield IGCC Polk Power Plant. U.S. DOE Publication "Techline DOE Sponsored Clean Coal Project Wins Power Magazine 1997 Award," June 5, 1997, U.S. Department of Energy.
[21] Calculated from TransCanada Pipeline's Press Release for the Redwater and Carseland Cogeneration Projects.
[22] Southern Illinois University, Coal Research Center, "Dry Flue Gas Desulfurization." http://www.siu.edu/~coalctr/index.html. $US converted to $Cdn at 1.50 exchange rate (1995$).
[23] For the PCC options, cost of labour ($2.08/MWh) has been calculated using information from EPCOR's Genesee 3 Expansion EIA: 60 people, 440 MW, $120,000 per person per year and 90% load factor. This labour cost has been assumed the same for the two natural gas options. Labour for IGCC and PFBC has been determined using EPCOR's staffing model (60 people) and adding 15 more operators and 5 more maintenance/technical staff to handle the additional complexity of the IGCC and PFBC plants. Labour for AFBC assumes adding 5 more operators and 2 more maintenance/technical staff.
[24] Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: $US 35.50/t ($Cdn 53.25/tonne), less transportation at approx. $32/tonne (Vancouver - Edmonton), 18 GJ/tonne gives $Cdn 1.18/GJ. This assumes that value of coal in Edmonton area is related to world market prices for coal.
[25] Gas price based on approximate daily AECO prices for June 28, 2001 from http://www.gasalberta.com/WebPublish/Web-Gas%20Price.htm
[26] Lower range of values for IGCC based on same reliability/uptime as for the other options. Higher range of values based on 11% worse reliability of IGCC when compared to the other options.

Glossary of Terms used in Table

AFBC - Atmospheric Fluidized Bed Combustion
BACT - Best Available Control Technology
CC - Coal Combustion
CO_2 - Carbon dioxide
ESP - Electrostatic Precipitators
FGD - Flue Gas Desulphurization
GHG - Greenhouse Gases
GJ - Giga-Joules
IGCC - Integrated Gasification Combined Cycle
kg - kilogram
LNB - Low NOx Burners
MWh - Mega-Watt per hour
NGCC - Natural Gas Combined Cycle
NO_x - Nitrogen Oxides
NR - not required
PCC - Pulverized Coal Combustion
PFBC - Pressured Fluidized Bed Combustion
PM - Particulate matter
ppm - parts per million
SCR - Selective Catalytic Reduction
SO_2 - Sulphur dioxide
SO_x - Sulphur oxides

The following summary compares the coal combustion options.

1. Efficiency and CO_2 – The coal combustion options are not as efficient as the natural gas options, and consequently all have significantly higher rates of greenhouse gas emissions. Of the coal-fired options, the IGCC process is the most efficient with the conventional subcritical PCC plants having the lowest efficiency.

2. SO_2 – Both the super and subcritical PCC options have high rates of sulphur emissions and require flue gas desulphurization to meet Alberta's standards. None of the other options require any add-on sulphur removal equipment.

3. NO_x – All coal-fired options, except perhaps IGCC, typically require both low NO_x burners and SCR/SNCR to meet a U.S. Standard for NO_x. The less-stringent standard in Alberta makes it possible for proponents to meet the Alberta standards with only low NO_x burners.[†] The natural gas options may not require SCR/SNCR to meet the more stringent U.S. standards if the gas turbines are properly equipped with LNBs to reduce NO_x by 90+%. If LNBs are not available to reduce NO_x to sufficiently low levels, the design may have to include a combination of LNBs and SCR/SNCR.

4. Particulate Matter – Of the coal-fired options, only the IGCC option does not require supplemental dust control measures. All other coal-fired options require either a baghouse or ESP, with the preferred option being a baghouse due to the added benefits of removing other pollutants such as mercury.

5. Mercury –With the exception of the IGCC option, all coal-fired options emit mercury from their stacks. The addition of a baghouse helps remove some mercury; however, the baghouse does not reduce the mercury down to the levels achieved in IGCC or the natural gas-fired plants.

6. CO_2 Sequestration – CO_2 must be considered in the design of all future power plants. Of all the options considered (coal and natural gas), only the IGCC option has a design that can facilitate CO_2 capture. This is because the relatively high pressure of the exhaust gases in an IGCC plant allows for easier CO_2 removal. Of course, the amount of CO_2 emitted from a natural gas-fired power plant is approximately half that emitted from a coal-fired plant.

7. Proven Technology – Both the subcritical and supercritical PCC options are well proven and are used in thousands of plants worldwide ranging in size from 100 MW to 1000 MW. AFBC plants are also well proven with hundreds in commercial operation in the 200 MW size and a few operating in Japan and France at 350 MW. PFBC plants are in commercial operation in Sweden, Japan and the U.S. with most in the smaller size (that is, less than 100 MW). A 350 MW unit is currently under construction in Japan. Most of the IGCC plants were initially built on a demonstration basis; however, all of them are now approaching a commercial level of operation in the range of 200-300 MW. The production of syngas from coal, which is the first step in an IGCC plant, has been around for many years and is a well proven technology. Both natural gas-fired options are commercially proven with thousands of installations worldwide in various sizes.

8. Capital and Operating Costs – The natural gas-fired options have the lowest capital cost, but even with their high efficiency, their operating costs are somewhat higher than coal at today's current gas prices ($4.00/GJ). Among the coal-fired options, the capital cost for the relatively basic design of the subcritical PCC option is the lowest, with progressively higher capital costs for the supercritical PCC, AFBC, PFBC and IGCC. Operating costs rank in more or less reverse order, with the AFBC and the supercritical PCC plants having the lowest operating costs.

9. Overall Levelized Cost to Produce Electricity – Comparing all options (coal- and natural gas-fired), the AFBC, super-PCC and the sub-PCC options can produce the least expensive electricity at around $43/MWh. The highest cost option is the NGCC at approximately $49/MWh at a $C4.00/GJ cost of natural gas. The IGCC system is also more expensive than other coal-fired options (generally 7-18% more, depending on the assumed reliability and other criteria used in the table), but is becoming competitive at today's electrical pool prices. At gas prices of approximately $3.25/GJ, NGCC becomes economic relative to the supercritical PCC coal-fired option. While the economics for all options is extremely sensitive to the cost of energy (coal or natural gas), all options considered have overall levelized costs within 10% of the average.

[†] The Two Elk Power Generation plant that was recently approved in Wyoming is designed to achieve low emissions using both low-NOx burners and Selective Catalytic Reduction. Ninety-five percent of the SO_2 will be removed using flue-gas desulphurization lime spray dryer.

4. Discussion

From an environmental standpoint, none of the coal-fired options is as favourable as the natural gas-fired options. However, among the coal-fired options, IGCC has the best environmental performance and comes very close to being as clean as the natural gas-fired options for all pollutants except CO_2. Natural gas-fired generation emits approximately half the CO_2 per amount of energy produced of any coal-fired option.

Based on the economic analysis presented in this paper, the IGCC option has an overall levelized cost of power that is within 7-18% of the supercritical PCC plant now being proposed in Alberta by EPCOR. The only area of concern with the IGCC option is its commercial viability on larger scale operations. With the number of IGCC plants moving into or already in commercial operation, this concern should be alleviated. Proponents of coal-fired plants should seriously consider IGCC, given its superior environmental performance for only a modest incremental increase in cost. The relatively high cost of today's natural gas (assumed to be $4.00/GJ) means it costs slightly more (12%) to produce electricity with the NGCC option than with the supercritical PCC option. However, at gas prices of approximately $3.25/GJ, the NGCC option has the same overall levelized cost as supercritical PCC plants. The natural gas combined heat and power cycle has very favourable economics even at today's gas prices due to its low capital cost and high efficiency.

With the deregulation of the electricity sector in Alberta, there is no longer a direct relationship between the cost of generation and the prices paid by consumers. In any hour, the price of generation is now set by the variable cost of the last unit dispatched. Even with the addition of more coal-fired capacity, consumers will typically be paying prices that are consistent with cleaner gas-fired generation. Allowing the proponents of new coal-fired generation to avoid the cost of installing more effective pollution control equipment on their plants will simply transfer the cost of the pollution onto society without providing offsetting benefits of lower cost power. While it is true that the addition of new coal-fired capacity will augment the supply of electricity in the province and lead to reductions in the market price of power in Alberta (from the average of $133/MWh in 2000), these same reductions would be realized with the addition of an equivalent amount of gas-fired capacity. The fact is that, following the addition of this new coal-fired generation, consumers will be paying prices that are consistent with the costs of cleaner gas-fired power plants but will experience comparatively higher levels of pollution from the new coal-fired facilities. The Alberta government should ensure that consumers get what they pay for – clean, highly efficient gas-fired generation. There is no need to settle for less.

5. Conclusions

This paper clearly shows that:

- Natural gas-fired generation has superior environmental performance and acceptable economic performance when compared with the coal-fired option.
- Of the coal-fired options, only the IGCC option comes close to meeting the environmental performance of the natural gas options and this is achievable with acceptable economical performance (IGCC has an overall levelized cost of power that is within 7 to 18% of the most economic options).
- All options, along with their associated pollution control add-ons, are feasible at today's gas, coal and electrical prices.
- With the pollution control add-ons, the environmental performance of the more conventional PCC coal-fired options can be drastically improved while still producing economic electricity.

All the electrical generation options reviewed in this paper can comfortably meet the new Alberta standards, in some cases without the additional pollution control equipment that would be required to meet the standards in the U.S. and certain other jurisdictions.

Alberta has clearly not adopted the approach of using Best Available Control Technology in designing the latest environmental standards. This review shows that many different, proven technologies are commercially available and could be economically included in the design of any coal-fired plant in Alberta. Unfortunately, because Alberta's standards are not as strict as in some other jurisdictions, proponents of coal-fired plants in Alberta will not be required to use these technologies.

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Canadian
Environmental
Law Association

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I truly believe that we need to phase out coal and nuclear powered forms of energy as soon as possible. Whether we like it or not I don't see that we have any choice. The air we breath depends on it. Thanks for all you can do.

Josephine Perkins

A Green Power Vision and Strategy for Canada

towards a sustainable electricity future for Canada

SummerhillGroup
Transforming Markets to Sustainability

A Green Power Vision and Strategy for Canada is the result of a series of five workshops held across the country by Pollution Probe and Summerhill Group. The workshop series, which was held between October 2003 and April 2004, assessed the potential for Green Power sources, such as wind, solar, biomass, geothermal, tidal and wave, to meet Canada's electricity needs. The series actively engaged more than 300 experts in Green Power, electricity generation and policy development and included representatives from government agencies, utilities, the private sector, academia and non-profit organizations, as well as from countries that are world leaders in Green Power development.

Visit the Pollution Probe website at **www.pollutionprobe.org/whatwedo/Energy.htm** to view the presentations from the workshop series, along with the following background documents:

Report of the Green Power in Canada Workshop Series (2004)
Primer on the Technologies of Renewable Energy (2003)
Promoting Green Power in Canada — Green Power Policies: A Look Across Borders (2002)

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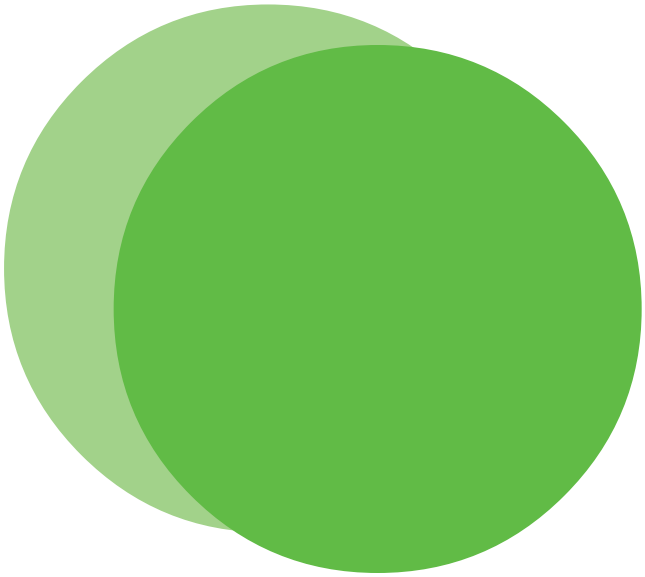
A long-term Vision and Strategy is needed to guide and accelerate the development of Green Power in Canada. The Vision must be shared among all jurisdictions and have broad stakeholder and public support. Strategies with targets and timelines are essential to implementing the Vision as has been demonstrated in countries that are world leaders in Green Power development. Canada has the technology and resource potential to join these world leaders and reap the multiple benefits that Green Power offers.

MAIN MESSAGES

1. Green Power is not a niche market — it can become a significant source of clean electricity across Canada. It has the potential to supply half of Canada's current annual electricity generation through concerted action over the next few decades. By moving aggressively on Green Power development now, Canada can become a full participant in the growing world market for cleaner energy technologies.

2. Green Power is essential to Canada's long-term response to the challenge of climate change. It also reduces smog and other forms of pollution that are linked to respiratory problems, hospitalizations and deaths.



BENEFITS

air pollution reduction
climate change mitigation
job creation
clean development mechanisms projects
rural development
green power
clean energy exports
price hedging
clean technology exports
energy security
electric power grid stability

INTRODUCTION

Electricity generation from wind, small hydro, solar, biomass and geothermal sources, once considered a niche market, is now moving into the mainstream. Ministers and government representatives from 154 countries at the June 2004 International Conference for Renewable Energies in Bonn, Germany, recognized the considerable benefits of Green Power. They committed to substantially increase, with a sense of urgency, the global share of renewable energy in the total energy supply. At the same time as the global community has been increasing its experience in the development of Green Power technologies, there has been a growing realization that now is the time for Canada to take advantage of its significant Green Power potential — to address the need for cleaner electricity and to serve both domestic and international markets.

From October 2003 to April 2004, more than 300 Green Power experts from government agencies, utilities, the private sector, academia, NGOs and several countries were actively engaged in the Green Power Workshop Series. They assessed the potential for Green Power to meet Canada's electricity needs and proposed strategies for achieving that potential.

A Green Power Vision and Strategy for Canada is the result of the workshop series. The Vision and Strategy, along with a leading-edge report on Green Power in Canada, reflects Pollution Probe's and Summerhill Group's work to turn the vast amount of information and advice received into a concise and progressive forward path.

Definition of Green Power

In this document, "Green Power" refers to sources of low-impact renewable energy that meet the criteria set by the Environmental Choice Program, currently the most commonly used definition in Canada. The Environmental Choice Program gives EcoLogo recognition to Alternative Source Electricity Generation from naturally occurring sources (such as the wind and sun) and from sources and technologies that have small environmental impacts (such as less intrusive hydro and certain biomass combustion). The criteria can be found at www.environmentalchoice.com/index.cfm?fuseaction=main.dspCompany.cfm&group=5.

There is scope for reviewing and revising these criteria to more specifically target electricity generation from Green Power sources. This Vision and Strategy does not preclude such a revision.

OUR VISION

Towards a Sustainable Electricity Future for Canada

The Vision *Towards a Sustainable Electricity Future for Canada* is an integral part of a larger Canadian vision that includes reduced air pollution and climate change impacts, improved human health, increased energy security, job creation and positioning Canadian firms among the world leaders in the manufacturing and exporting of innovative technologies.

While this Vision and Strategy focuses on Green Power, it recognizes that important contributions must be made by energy efficiency and conservation measures. There is also a role for cleaner electricity from other sources, such as ecologically sustainable larger-scale hydro and improved traditional technologies. Policy recommendations for these sources and measures are not included in this document as they were beyond the scope of the workshop series.

The following list shows sustainable electricity future options in order of priority. It highlights the importance of Green Power to the future electricity mix.

1. Energy efficiency and conservation;
2. Green Power that meets the criteria for EcoLogo certification;
3. Ecologically sustainable larger-scale hydro and other renewables;
4. Combined heat and power using natural gas; and
5. The cleanest and safest technologies among the remaining options.

TARGETS AND TIMELINES

Setting Green Power targets requires looking beyond present barriers and assessing the long-term potential for mature and emerging Green Power technologies to meet future electricity demand. Using the best information available for each technology, a portfolio of options has been used to propose a total Green Power generation target for the year 2025.

Aggressive targets for Green Power development in Canada are possible given the total generation potential available to the country.

Green Power initiatives underway or announced by federal and provincial governments could represent seven per cent of electricity generation in Canada by 2010. The total technical potential of Green Power for the long-term is much higher when estimates are included for all of Canada's Green Power resources and when expected improvements in technology are considered. The total potential is at least 340 TWh, or more than half of the current annual electricity generated in Canada (~600 TWh).

The following table contains a potential Green Power portfolio for 2025, showing the contribution by various Green Power technologies. The capacity factor is the percentage of actual electricity output expected in a given time period (generation) compared to the maximum possible if the source ran full time at its peak potential (capacity). Generation (TWh) has been used to set the targets for Canada as it shows the actual electricity that would be produced from Green Power sources.

The mix of Green Power technologies used to meet the target in 2025 will likely differ from the portfolio presented as some technologies could generate less than expected while others could generate more. Targets have also been suggested for 2010, 2015 and 2020. The focus of the Vision and Strategy is on the total electricity generated by Green Power for each target year.

Potential Green Power Portfolio for 2025

TECHNOLOGY	CAPACITY (MW)	CAPACITY FACTOR (PER CENT)	ELECTRICITY GENERATION (TWh)
Wind — onshore	21,000	30	55
Wind — offshore	3,400	40	12
Small hydro	10,000	50	44
Biomass	4,500	80	32
Geothermal	500	95	4
Solar	1,000	14	1
Wave	500	30	1
Tidal	500	30	1
TOTAL	**41,400**		**150**

The target for 2025 is 150 TWh of electricity generated by Green Power.

Green Power Targets for Canada

45–60 TWh of green power by 2010.

90 TWh of green power by 2015.

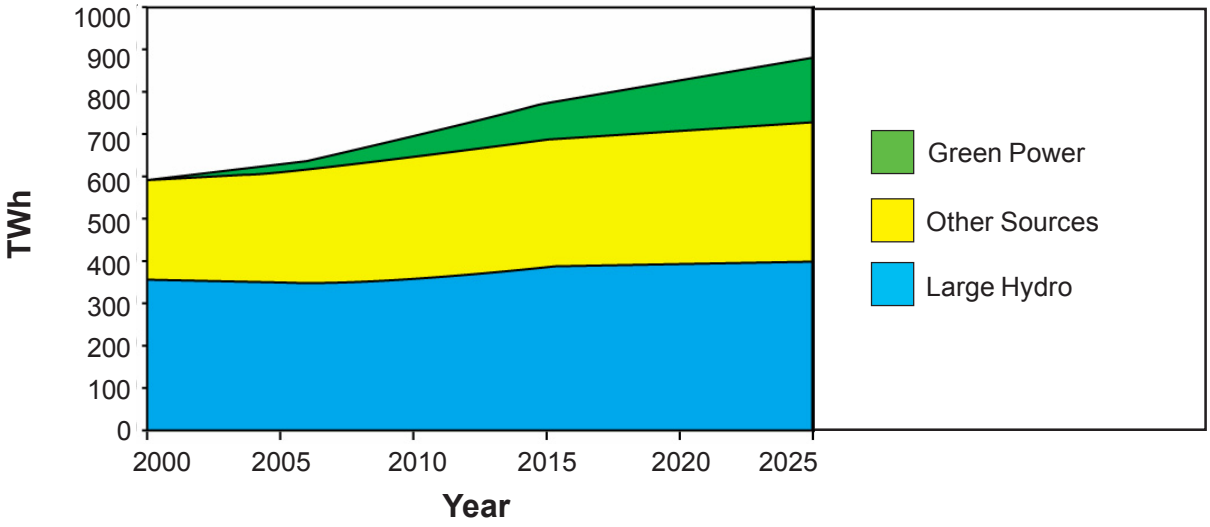
120 TWh of green power by 2020.

150 TWh of green power by 2025.

The impacts of achieving the Green Power targets are illustrated in the following graphs. The targets are shown relative to the total business-as-usual (BAU) projections for electricity generation of the National Energy Board (NEB 2003). The graphs have been modified to include Green Power generation as the targets are achieved.

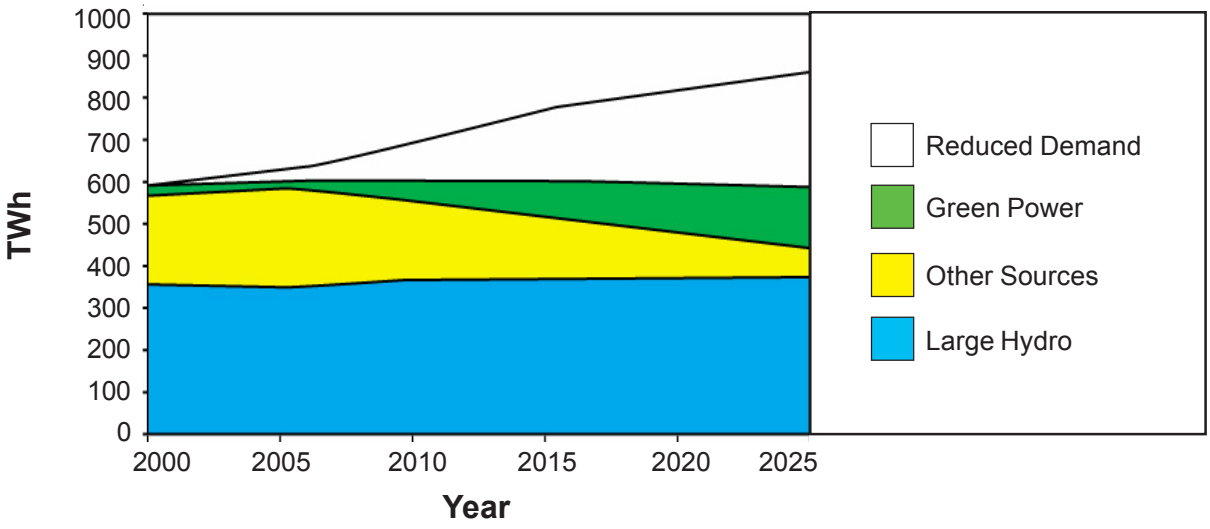
Under the Business-As-Usual Scenario, Green Power represents 17 per cent of the electricity mix by 2025. As the total demand for electricity increases, there is an increase in generation by Other Sources (e.g., fossil fuel and nuclear power).

Business-As-Usual Scenario



Under the Stable Demand Scenario, total domestic electricity demand is stabilized at the current level (600 TWh). Green Power represents 25 per cent of the mix by 2025 and there is a decrease in generation by Other Sources. To achieve this scenario, electricity demand would have to decrease 31 per cent by 2025 relative to the National Energy Board's projection for business as usual.

Stable Demand Scenario



STRATEGY

To develop Green Power to its full potential in Canada, concerted action will be required on several fronts. Three priority areas for action are identified below, complemented by seven additional areas that need to be addressed to remove the barriers to, and achieve the potential for, Green Power development and deployment.

The following strategies and recommendations do not allocate responsibilities by jurisdiction. It is expected that federal, provincial, territorial and municipal governments will select portfolios of action that take into account their specific resource potentials, economic circumstances and the value of using combinations of initiatives. They should all develop roadmaps outlining strategies, targets and timelines and begin implementation so that by 2010 Canada has not only achieved the first shared national target, but has put in place the policies and incentives to achieve later targets.

All jurisdictions and sectors need to work together in a spirit of cooperation in order to fully implement the Vision and Strategy.

Priority 1 — Leveling the Playing Field

Billions of dollars have been invested in fossil fuel technologies and nuclear power to ensure that Canadians have reliable and low-cost supplies of electricity. It is time to invest in Green Power sufficiently over the long-term to develop viable domestic and export markets for Green Power and related technologies.

Recommendations:

- ***Renewable Portfolio Standards, Targets or Equivalent Policy Commitments***, such as feed-in tariffs, should be established by provincial, territorial and key municipal governments. These should include tailored targets for each jurisdiction and specified timeframes for the development of Green Power technologies. The national targets can be achieved through a combination of regional strategies supported by federal incentives.

- ***A Green Power Production Incentive*** (GPPI) should be established by the federal government and complemented by the provinces and territories. It should support the development of market-ready Green Power technologies that require additional support. The existing federal Wind Power Production Incentive (WPPI) should be substantially increased and either become part of or run parallel to the GPPI.

Alberta, British Columbia, New Brunswick, Nova Scotia, Ontario and PEI have implemented, or are working on, voluntary and mandatory Renewable Portfolio Standards.

- ***Green Power Procurement***. Federal, provincial, territorial and municipal governments should lead by example by setting aggressive targets for Green Power procurement for their own use. All new public buildings should be built to strict energy efficiency standards and should obtain a set percentage of their energy needs from Green Power generation. A program should be established to encourage the private sector and institutions to procure Green Power.

- ***A Renewable Energy Certificate System*** should be established to support the implementation of Renewable Portfolio Standards. The system should be voluntary and flexible. Inter-provincial cooperation could reduce overall costs and support an enhanced national target for Green Power development. Provinces and territories could require that a share of their Green Power targets be generated by local sources.

- ***A System Benefits Charge*** (SBC), which is a small surcharge added to consumers' electricity bills, could be used to finance specific Green Power policy initiatives. There would be a cost to consumers, which would be offset by improved environmental quality and human health.

Alberta has required that 90 per cent of the electricity used for public buildings be from Green Power sources by 2005.

Priority 2 — Supporting Innovative Technologies

There is an opportunity for Canada to be among the world leaders in the development of Green Power technologies. For example, Canada has tremendous resources that can be tapped for biomass and ocean-based power. Innovative technologies designed to harness this power could be marketed worldwide. Capitalizing on these opportunities will require leadership, innovation and focused support.

Recommendations:

- ***A Comprehensive Strategy*** should be developed for the research, development, demonstration and commercialization of emerging Green Power technologies by the federal government working in cooperation with the provinces, territories and industry. Existing R&D funding programs should be refocused or enhanced to support implementation of the strategy, and gaps should be filled through new initiatives.

Québec has set targets for 1,000 MW of wind and 100 MW of biomass by 2010.

- ***Centres of Excellence*** for various Green Power technologies should be established throughout Canada. Objectives for each Centre should be set in keeping with regional resource profiles.

- ***Sustainable Development Technology Canada*** (SDTC) has had its role strengthened to serve as a catalyst for the demonstration and pre-commercialization of sustainable development technologies, including Green Power. The provinces should partner with SDTC or establish similar mechanisms to develop innovative Green Power technologies to serve their regions.

- ***Technology Road Maps***, such as those being developed by the SDTC, should be prepared to help the private sector select and develop the best technology options to meet future technical, environmental and market needs.

Ontario has proposed a Green Power target of 10 per cent of its total energy capacity by 2010.

Priority 3 — Engaging Canadians in Achieving the Vision

To achieve the Vision for Green Power development in Canada, it will be essential to gain widespread public support for national and provincial/territorial targets. Municipalities will also be important focal points for this activity.

Recommendations:

- ***Community Engagement*** should become a standard component of local Green Power planning by governments and industry. In areas with substantial Green Power resources, communities should be made aware of the resources in their regions and how Green Power development can offer economic benefits and contribute to the national Vision. Specific sectors should be informed of the role they can play in the development of Green Power (e.g., farmers who can lease their land for wind turbines).

- ***Community-based Projects*** should be encouraged through incentives and by streamlining the regulatory process to support public investment in Green Power.

- ***The Market Incentive Program*** should be expanded to increase funding support for the sale of electricity from emerging Green Power sources and should be extended beyond 2006 to support longer term contracts for Green Power. The provinces and territories should be engaged to develop a broader-based consumer green energy rebate program.

- ***A Comprehensive Public Education and Outreach Strategy*** should be developed to inform Canadians broadly about the Vision for a sustainable electricity future for Canada and to promote awareness of the benefits this future promises. Resources to support implementation of the Vision should be developed for use by community leaders, educators, NGOs and the private sector.

Windshare is a project developed by the Toronto Renewable Energy Co-operative and jointly owned with Toronto-Hydro, in which more than 400 members have invested in a wind turbine located in Toronto.

Supporting Strategies

Work will be needed in many areas to ensure that Green Power technologies become mainstream. The following recommendations address key requirements for these new technologies to successfully gain market share.

Accessing the Power Grid

A robust Green Power industry cannot develop without open and fair access to the power grid. The best locations for Green Power sources, such as wind, small hydro and geothermal, may be located far from existing transmission lines. The grid will have to be extended to appropriate areas with increased capacity.

Saskatchewan has committed to meeting its needs for incremental power to 2010 through Green Power.

Recommendations:

- ***Expansion of power grids*** to support implementation of the Green Power targets should include identification of areas that offer viable green power resources, assessment of transmission grid needs, and environmental assessments of the projects, with full consideration given to the environmental benefits of Green Power.

- ***Transmission planning*** should proactively support the expansion of Green Power as the aging grid is rebuilt.

- ***The cost to extend transmission lines*** should be shared by the overall customer base or co-funded by governments in public-private partnerships, once developers have paid a reasonable price to connect to the grid.

PEI is proceeding with a Renewable Portfolio Standard of 15 per cent by 2010 and is considering 100 per cent by 2015.

- ***Efforts towards grid integration and coordination*** should begin now among provinces and territories to facilitate interconnection and the optimal development and sharing of Green Power resources across Canada.

Mapping Green Power Resources

To fully develop Canada's Green Power resources, it is essential to know where they are located. Mapping of Green Power resources in Canada is crucial for strategic policy support and the development of Green Power industries. While some work has been done (e.g., the federal Wind Atlas that is under development), there is an immediate need to identify the location and potential of wind, solar, hydro, tidal, biomass, geothermal and wave resources in Canada.

BC Hydro has developed a comprehensive map of Green Power resources in British Columbia.

Recommendations:

- ***Resource maps*** should be developed for all Green Power resources across Canada through the cooperation of federal and provincial/territorial government agencies. The resource maps should be available to the private sector and the public.

- ***Assessment of backup for intermittency*** should be part of the mapping of Green Power resources. The assessment should include the use of multiple locations, potential synergies of various Green Power resources and the existing potential of conventional sources, such as hydro or natural gas, to serve as backup for intermittent Green Power resources.

Establishing Mechanisms for Distributed Generation

Policy frameworks for Green Power generation often overlook distributed generation (i.e., Green Power generation units located close to where the energy is used), in spite of the potential this option offers to reduce demand for central, large-scale electricity generation and to reduce peak demand for grid electricity (i.e., peak-shaving). Distributed Green Power generation also offers significant benefits to remote communities.

Recommendations:

- ***Aggressive national and provincial targets*** should be set for solar roofs, supported by capital buy-downs, to facilitate their widespread use (e.g., Germany has a target of 100,000 solar roofs).

- ***Provincial net metering programs*** should be developed to enable proponents of distributed generation to sell power back to the grid.

- ***Green Power generation in remote communities*** should be subsidized to be competitive with other subsidized fuels (e.g., diesel) used in electricity generation.

Streamlining Zoning, Planning and Permit Requirements

As several Green Power technologies are relatively new to Canada's electricity mix, municipal and regional planners need guidance to deal with the special needs of Green Power development. In particular, assistance is needed to address the permitting bottlenecks that prevent rapid deployment of Green Power technologies.

Recommendations:

- ***Planning and permitting practices should reflect official government targets***. Provincial governments should assist municipalities in addressing bottlenecks to Green Power development on both private and Crown land. For example, they should recommend streamlined models for zoning standards and should clarify Crown land use policies. Where possible, the processing of planning applications for Green Power projects should be centralized in one provincial/territorial ministry.

- ***Environmental impact assessments*** for Green Power projects should be tailored to the needs of specific technologies. In addition, streamlined approval processes should be developed for technologies proven to be low-impact. These assessments should be harmonized among jurisdictions so that one process offers federal and provincial/territorial approvals.

Developing Standards to Ensure Quality and Safety

As Canada gears up to introduce new technologies for centralized and decentralized electricity generation, a broad range of standards need to be developed to ensure the most effective deployment of these technologies. The Canadian Standards Association, or comparable agencies, should be engaged to develop and oversee the development of these standards.

Recommendations:

- ***An assessment should be conducted of the standards needed*** to facilitate the timely introduction of a diverse mix of Green Power technologies in Canada.

- ***Standards should be developed*** to ensure that equipment will meet environmental performance requirements and address quality, safety and the ability to withstand Canadian weather conditions. Consideration should be given to adopting international standards that are well-developed and proven.

The Canadian Standards Association is actively developing standards for renewable energy technologies and distributed energy systems.

- ***National interconnection standards for the installation of small distributed generation systems should be developed***, based on the guidelines developed under the Canadian Micropower Connect committee initiative. These standards should be adopted by all provinces and territories once they are approved by the Standards Council of Canada.

Preparing the Labour Force

International experience indicates that a lack of qualified personnel can be a significant barrier to the development of Green Power. In Ontario alone, it is estimated that approximately 2,000 additional engineers and technicians will be needed to achieve recently announced Green Power targets.

Recommendations:

- ***Primary and secondary school curricula*** should include the study of Green Power and energy efficiency to ensure that students learn basic information and are made aware of career opportunities in these fields.

- ***Post-secondary curricula*** should be developed to support the training (and retraining) of skilled staff for the emerging Green Power market. Government and industry should work with universities, colleges and technical institutes to develop curricula.

The Association of Canadian Community Colleges (ACCC) and Natural Resources Canada (NRCan) have teamed up to kickstart a national training program in renewable energy.

- ***Training courses*** should be developed to prepare utility personnel for the special needs of the Green Power market.

Setting Up Green Power Coordinating Bodies

For the Green Power Vision and Strategy to be implemented successfully, it must be built on strong provincial/territorial foundations. Its implementation will require a coordinated effort by governments in all jurisdictions, as well as effective engagement of stakeholders and the public.

Recommendations:

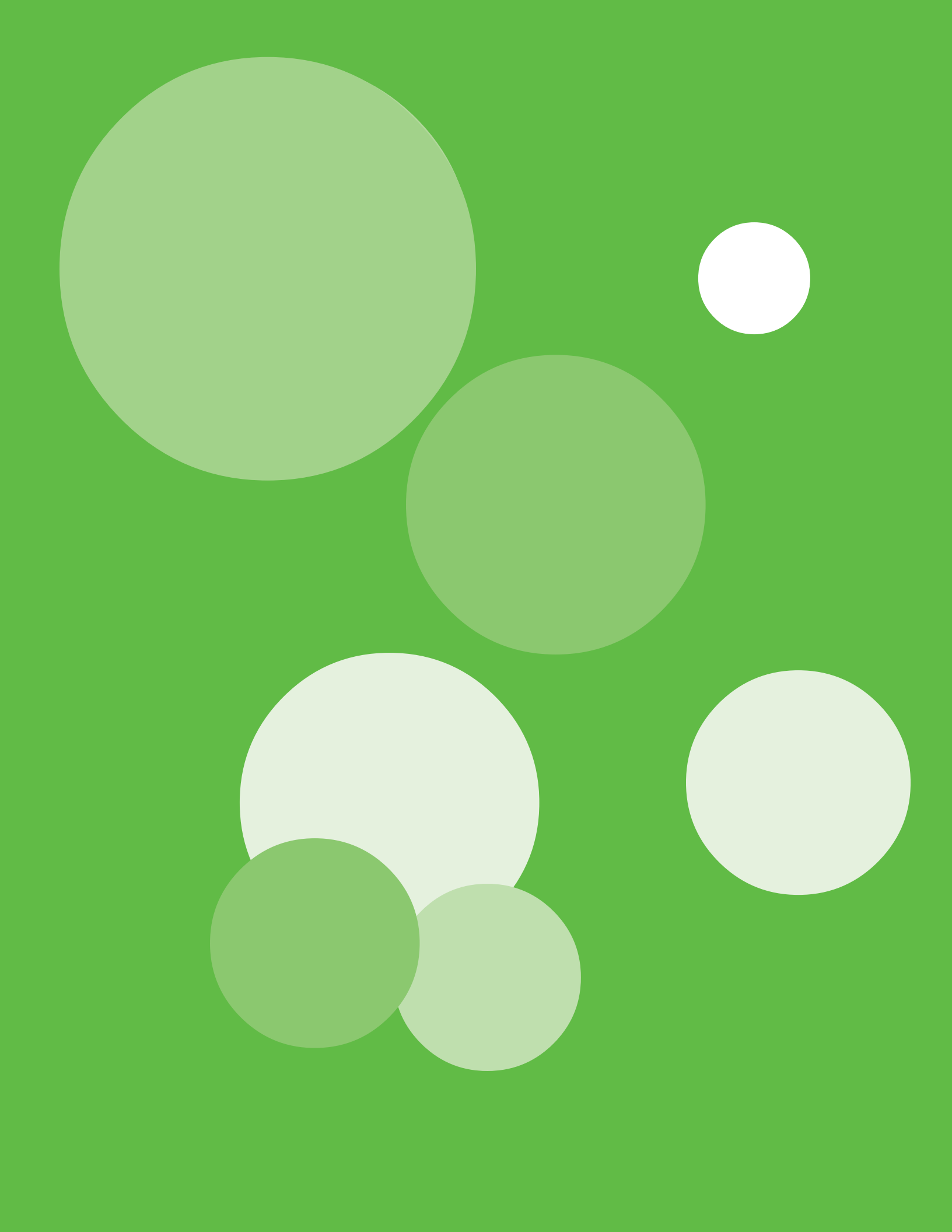
- ***Provincial/territorial Green Power coordinating bodies*** should be created to engage relevant ministries and stakeholders to oversee the establishment and implementation of provincial/territorial plans with targets for Green Power development and deployment.

Alberta's Clean Air Strategic Alliance (CASA) is a working group consisting of government, industry and ENGO representatives. It has formed a sub-group to develop strategies and programs to reach the government-set Green Power target, and to suggest solutions for related issues, such as transmission access.

- ***A new national coordinating body or network*** should be established with representation from relevant federal departments, provinces, territories and key stakeholders. Its mission should be to build support for a shared vision for Green Power, and to oversee the implementation of the Green Power Vision and Strategy in Canada. It should identify new opportunities and engage in problem-solving to overcome barriers.

The Canadian Energy Efficiency Alliance was created in 1995 as a public advocate for energy efficiency in Canada. It monitors and reports on Canada's progress on energy efficiency.

- ***A Canadian Renewable Energy Alliance*** should be established as a multi-stakeholder, non-governmental organization to act as a public advocate for the Vision and Strategy. It should monitor and report publicly on progress toward implementing the Green Power Vision and Strategy for Canada.



POLLUTION PROBE
CLEAN AIR. CLEAN WATER.

Green Power
Provincial/Territorial Targets and Policies

Information Updated: September 2005

Nova Scotia — RPS for 5 per cent of total generation must be renewables by 2010.

- Sources include: small-scale hydroelectricity, wind power and biomass fuels
- Sources must be built after 2001 as per Electricity Act
- In past 16 months — 100 MW renewable energy contracts awarded

New Brunswick — RPS for additional 10 per cent of total consumption by 2016.

- Most common sources include: wind, biomass, hydro and landfill gases
- Power purchase agreement signed for 20 MW of wind
- By 2016 — up to 400 MW of wind energy to be purchased by NB Power.
- Summer 2005 — NB Power to issue call for EOI for wind

Prince Edward Island — RPS for 15 per cent of total generation by 2010. Exploring 100 per cent by 2015.

- December 2004 — Renewable Energy Act received royal assent that includes an RPS and guaranteed feed-in tariff for community, wind cooperative and large systems
- RE Act requires utilities to acquire at least 15 per cent of their electrical energy from renewables by 2010
- Sources include wind, solar, hydro and biomass
- February 2005 — EOI for oil seed extraction and biodiesel manufacturing plant
- Summer 2005 — 30 MW wind farm proposed (based on a government and co-op ownership model). Responses received for RFP for project design services and RFI for project financing.
- Spring 2005 — announced intention to develop a wind-hydrogen village demonstration project

Newfoundland — RFP for Wind Power Development Strategy.

- February 8, 2005 — RFP issued. Proposals to provide recommendations to government on the development of a Wind Power Development Strategy
- Summer 2005 – Climate Change Action Plan 2005 released. A comprehensive energy plan consultation document to be released in 2005

Québec — Targets for 2,000 MW of wind by 2014 and 100 MW of biomass by 2008.

- Contracts signed for 39 MW of biomass by 2007
- Contracts signed for 990 MW of wind
- June 2005 — Bid selected to purchase 8.1 MW of biomass
- June 2005 — Hydro-Québec to issue a call for tenders for 2,000 MW of wind
- By 2013 — 3,500 MW expected from wind power

Ontario — RPS for 5 per cent (1,350 MW) by 2007 and 10 per cent (2,700 MW) by 2010 of total generation to be new renewables.

- June 2004 — RFP for 300 MW released. Projects announced for 395 MW
- April 2005 — RFP for 1,000 MW of 20 to 200 MW generation facilities
- July 2005 — RFP for 200 MW generation under 20 MW
- RFP sources include wind, water, solar, biomass and landfill gas

Manitoba — Target for 1,000 MW of wind by 2014.

- October 2004 — wind power strategy developed
- By end of 2005 — 99 MW wind project to be completed. 12 test wind turbines are now operational

Saskatchewan — Target for 150 MW of wind by 2005. 100 per cent of new generation until 2010 to be operations that do not add to GHG emissions.

- Projects include: wind (major component), energy conservation, small hydro, distributed generation (includes cogeneration), and Environmentally Preferred Power Program (low environmental impact generation such as, flare gas and heat recovery systems)
- May 2005 — 32 MW RFP released
- December 2005 — 150 MW wind power project to be completed (under construction)

Alberta — Target for 3.5 per cent of total generation by 2008.

- 3.5 per cent renewables target represents about 560 MW of new capacity
- January 2005 — 90 per cent of electricity used in provincial government operations must be from renewables and alternative power
- Currently, Canada's leader in wind power with 275.4 MW installed capacity

British Columbia — 50 per cent of new generation to be clean energy by 2012.

- Voluntary goal for electricity distributors
- Sources include wind, solar, ocean, biomass, hydro, geothermal, fuel cells, efficiency measures and cogeneration
- April 2005 — release of Alternative Energy and Power Technology: A Strategy for BC

Territories

Yukon: Yukon Development Corporation 2004 Progress Report includes 1 MW wind increase by 2006

Northwest Territories: NWT Energy Strategy includes 10 per cent of total energy supply by 2010, 25 per cent by 2025 from renewable energy sources (excluding industrial energy supply)

Nunavut: Energy Action Plan includes increase of renewable energy by 2008 in 1 or 2 community projects. RFP was issued in 2003 for 1.3 MW, however, there is no implementation date

P·U·R·E

POWER UP!

Renewable Energy Co ⚡ Operative

August 22 05

Supply Mix

The Power Up Renewable Energy Co-operative (PURE) wishes to make a submission in respect to the recent request for submissions from stakeholders associated with the supply mix for electrical power.

PURE's submission recognises the four 'issue areas' identified by the OPA.

1. Appropriate analytical planning approaches.
   PURE supports this approach and believes it to be the only sensible thing to do. Among 'other quantifiable and qualitative risks' one should include health/medical since it is believed that these are directly influenced by the method of generation over its life cycle.

2. Appropriate approaches to constructing Conservation and Demand portfolios.
   PURE is of the view based upon the experience gained through its Green Power generation project and Reduce the Juice conservation project conducted this year in Shelburne, Ontario, that one of the most effective methods for exercising management over conservation and demand is by introducing instruction and practical programs into schools and colleges. We have found that the student population by and large is fervent believer in these aspects and want to implement actions, particularly in their home lives that will have a positive effect. Through these actions their parents become involved and effect change.

   Further we are of the view that there is much to be obtained by rapidly moving to community distributed power generation and delivery systems primarily using renewable energy sources. We are seeing the beginning of this and PURE is active alongside other community groups in achieving this method of generation management and market structure

3. Assessments of different supply technologies and resources in the Ontario setting.

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In the shorter term with regard to community distributed power it is considered this can best be served by wind and bio-mass/bio-waste solutions. In the medium term some localities can install micro-hydro and solar generation. With regard to heating requirements geo-thermal technology must be applied.

We believe for residential and small business applications incentives must be offered to install the effective supply technology appropriate to the local area. Overall, what is envisaged, is a distributed power generation mix appropriate to the geographical location and the entity involved. As Minister Duncan stated "We support it entirely…..It encourages small businesses, farms, schools (and colleges), community co-ops and individual households and others to come to the table"

Some of this we believe can be brought on stream fairly quickly and it can be of a demand type configuration.

4. Appropriate methods to assess the impact on the natural environment of supply options.

   PURE has to support this. We are of the belief that by installing generation capability without due regard for the environment is inviting trouble during the life cycle either directly or indirectly. We believe the OPA and the governments of Ontario must be responsible and far sighted enough to consider the potential causes and effects on the environment which includes the health and welfare of all living organisms and making a responsible judgement and decision.

Power Up Energy Co-operatives wish to extend its appreciation for providing the various Stakeholders to make comments on the area of Supply Mix.

Yours truly,
Anthony Howard
Executive Director
Power Up Renewable Energy Co-operative.

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Submission

to the

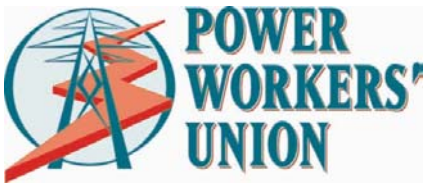
Ontario Power Authority

concerning

The Future Supply Mix for Ontario

Power Workers' Union

August, 2005



Executive Summary

The PWU offers the following submission in response to the Ontario Power Authority (OPA) Call for Written Submissions based on a request from the Minister of Energy to have the OPA provide recommendations on the development of an Integrated Power Supply Plan. The findings included in the report come from several sources, each providing a particular perspective on the issues related to supply mix in Ontario:

- Global Energy Decisions LLP (Global Energy), known for its objective and detailed market-based electricity price modelling expertise, provided preliminary results of the cost impacts associated with the implementation of current Ontario Liberal Government electricity policy;
- Elenchus Research Associates Inc. provided specific analysis with respect to natural gas prices in response to the lack of any detailed analysis by the Government on this issue. Elenchus also substantially assisted in compiling this submission to ensure a clear view of other associated issues;
- Both provided views of the environmental impacts associated with coal-fuelled generation.

There are significant costs and risks associated with the policy direction contemplated by the Government's rush to close Ontario's coal-fuelled stations. This directive and the announced associated actions seriously jeopardize Ontario's future supply adequacy, reliability, safety and price. It is a policy direction that is not based on sound planning or supported by a comprehensive assessment of the costs and benefits.

The public record should contain an assessment of the coal shut down policy that is based on objective, quantifiable data. It is the OPA's responsibility to conduct this analysis although it may appear that the Ontario Government has, through conflicting legislation and directives, compromised the OPA's legislated requirement to "*conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario".*

The PWU offers this submission as an initial step in providing analysis of the benefits of:

- rehabilitating existing coal stations with air quality abatement technology;
- returning to service all existing nuclear generation;
- ensuring these forms of generation supply remain part of Ontario's electricity supply through continuing coal and nuclear life extension rehabilitation; and
- proceeding with new construction of power plants utilizing the best available technology in both fossil and nuclear generation.

The findings that follow represent the PWU's views on what Ontario needs to do to have a viable electricity plan for the future.

To ensure that there is an adequate, reliable, secure and reasonably priced electricity supply, Ontario must have a diverse supply resource mix that capitalizes on existing assets; a highly skilled work force; and reasonable conservation, demand management and demand response programs. As well as an objective analysis of all options, any change to the manner in which Ontario's energy needs are met should be subject to proper planning, including full compliance with the Environmental Assessment Act.

Findings

Global Energy analyzed the difference in power prices, emission, power imports/exports and total costs for serving Ontario's load during the 2006-2025 period by comparing two alternative future developments of the market. In the Base Case scenario it is assumed that the coal plant retirements and procurement of replacement capacity proceeds as planned. In the Clean Coal Case it is assumed that all existing Ontario coal plants are retained and kept operational for the 2006-2025 period while being required to install state-of-the-art emission controls to reduce NO_X and SO_2 emissions.

The study is based on Global Energy's Spring 2005 Market Advisory report for the Northeast markets, which is a comprehensive outlook and analysis of the power markets in Northeastern United States and Canada. The forecast was modified with respect to Ontario's load, natural gas prices, and new Ontario resources coming on line in the 2005-2010 period.

The main results of Global Energy's analysis can be summarized as:

- Retiring Ontario's coal-fuelled plants significantly changes the demand for natural gas in the region. In the Base Case, Ontario's gas demand is forecast to grow from about 120 BCF per year in 2005, reaching 260 BCF per year by 2010 and then increasing to about 340 BCF per year by 2025. This increased gas demand also impacts the fixed infrastructure costs for bringing this gas to market. Global Energy estimates that the total fixed infrastructure costs resulting from this increased demand is about C$3 billion over and above the direct impacts on the electricity generation costs.
- About 80 percent of the emission reductions achieved from closing the coal plants could be achieved by retrofitting these plants with advanced emission controls at a cost that is only about 20 percent of the total costs associated with closing the coal plants.
- An important uncertainty in the Global forecast is the level of electricity demand growth over the forecast period. Global's base case reflects the Median Demand Case from the IESO's July 2005 10-year outlook. Combining the high natural gas price scenario with the IESO's 10-year high demand case increased estimated costs for closing Ontario's coal plants to about C$ 11 billion, or about 38 percent above the Clean Coal scenario.
- Coal closure will make Ontario more dependent on other jurisdictions for electricity than will occur if clean coal is utilized. This is particularly true under the high gas price/high demand scenario where retaining coal and nuclear plants ensures adequate domestic supply through the planning period.

Among other risks that are assessed, Global points out that their modeling does not account for natural gas price volatility or additional investments in electricity transmission upgrades that may be necessary to facilitate the closure of Ontario's coal-fuelled generating stations.

The gas supply and price forecast uncertainty is a significant risk in replacing coal-fuelled generation with gas-fired generation. Ontario's natural gas consumers could experience gas price increases and volatility related to incremental gas load to gas-

fuelled generators. This could increase Ontario's natural gas demand by 30% in a very short timeframe—the equivalent amount of gas currently used by 2.4 million residential consumers.

With this substantial increase in natural gas consumption, new infrastructure will be required to ensure adequate natural gas supply, storage and deliverability to and through Ontario. Without this massive investment there will be no way to mitigate the risk on price levels and volatility driven by the unique consumption demands from these new gas-fired plants. In addition, the Ontario gas market has not yet experienced nor has it been designed to operate with the large daily volumetric and deliverability swings this will bring. Lastly, it is questionable whether this required gas infrastructure can be put in place to meet the Government's short coal closure timeline.

The forecasted price level for natural gas has a significantly greater probability of moving to the high side than to the downside. Both crude and natural gas product pricing have or are in the process of establishing new floors as a consequence of internationalization of energy markets and dramatic upward increases in overall international demands for both fuels. Some forecasters are suggesting that there has been a structural change in the pricing of both products that leads to greater volatility and higher price levels.

The IESO most recent 10 Year Forecast identifies significant system reliability concerns related to the closure of the coal-fuelled plants.

- Coal closure will result in higher transmission costs related to major and complex transmission projects required to maintain system reliability.
- The IESO's supply demand forecast indicates that should there be any slippage in the planned in-service dates for the new replacement generation projects, system adequacy and reliability will be put at risk.

At this time demand is increasing and there is an urgent need to replace and/or refurbish a substantial portion of Ontario's generation fleet. It is therefore inappropriate to close existing generation plants that provide reliable and affordable electricity before the end of their economic lives.

Clearly, coal closure presents significant risks to the system that will be difficult to manage effectively. Failing to consider clean coal as an option in Ontario's supply mix could be extremely costly resulting in higher electricity as well as gas costs. This result in turn will jeopardize Ontario's economic and social welfare. Other jurisdictions recognize the benefits of clean coal supply vis-à-vis gas. As a result, many jurisdictions are upgrading their coal plants and retrofitting them with clean coal technology. In Ontario, the Government is pursuing a decision based on short-term political expediency that threatens to eliminate a long-term supply opportunity that Ontario can ill afford to do without.

The PWU energy plan enhances supply adequacy, reliability and reasonableness of price and maximizes the value of the existing system in which Ontarians have already made significant investments. Existing coal generation retrofitted for clean coal generation with extended service life for all units beyond 2025, and new clean coal generation where supported by cost benefit analysis must be considered as an option for Ontario's future supply mix.

The OPA needs to be prudent and have a plan that is not exposed to higher and more volatile natural gas costs, does not place undue reliance on alternate supply options that can provide reliable capacity and is responsive to a high demand growth scenario. The province should recognize the potentially deleterious economic impact and risk associated with coal closure. Such an assessment will lead them to the same conclusion we have reached. It is time to step back from their determination to execute a supply plan which has not been independently, analytically and publicly evaluated. Ontario's power consuming industries, commercial businesses and residential users deserve a more balanced energy strategy. By adhering to rigorous and balanced analysis, the OPA's review of Ontario's future supply mix will result in a cleaner environment sooner and at substantially lower costs and risks than would otherwise be achievable.

Table of Contents

Executive Summary i

Table of Contents i

1 Introduction 1

2 OPA's Responsibility for Ontario's Supply Mix 3

3 Supply Policy 6

3.1 Continued Operation of Existing Generation 6

3.2 Diverse Mix of Supply Resources 7

3.3 Proper Planning and Compliance with Environmental Assessment Act 8

4 Cost of Phasing-out Ontario's Coal-fuelled Generation 9

4.1 Market and Cost Assessments 9

4.2 Reserves 17

4.3 Imports 19

4.4 Emissions 20

4.5 Risk Assessment 21

4.5.1 Demand 21

4.5.2 Supply 22

4.5.3 Transmission 22

4.5.4 Loss of Skills and Fuel Contracts 22

4.6 Summary On Cost of Phasing-out Ontario's Coal-fuelled Generation 23

5 Natural Gas Issues 24

5.1 Natural Gas Infrastructure Costs 24

5.1.1 Gas-fired Generation Infrastructure 24

5.1.2 Cost Benefit of Replacement of Coal-fuelled Generation 25

5.2 Natural Gas Pricing Dynamics 30

5.2.1 Natural Gas Pricing Dynamics 30

5.2.2 Mitigate Reliance on Natural Gas 37

5.3 Natural Gas On-going Supply Adequacy and Reliability 41

6 Implementing the Supply Policy Framework 44

6.1 Continued Operation of Existing Generation 44

6.1.1 Retrofit of Coal Generation with Clean Coal Generation 44

6.1.2 Risks related to Closure of Coal-fuelled Generation 52

6.2 Diverse Mix of Supply Resources 55

6.2.1 Clean Coal in Ontario's Future Supply Mix 56

6.2.2 Realistic Expectations of Renewable Energy Sources 57
6.2.3 Conservation and Efficiency 57
6.2.4 Highly Skilled Energy Workfor 58
6.3 Proper Planning and Compliance with Environmental Assessment Act 58
7 Consideration for CDM Programs 59
8 Assessing Environmental Impacts 60
9 Conclusion 61

1 INTRODUCTION

The Ontario Power Authority (the "OPA") has issued a Call for Written Submissions[1] with regard to the Minister of Energy's May 2, 2005 request to the OPA for a report that addresses the Government's goals for an Integrated Power Supply Plan[2].

The Minister requests that the report be based on the OPA's internal resources, the Government's plan to replace coal-fuelled generation in Ontario, expert advice solicited from Ontario and abroad, and stakeholder input in a manner developed at the discretion of the OPA.

The OPA has identified the following issue areas on which advice would be especially helpful:

1. Appropriate analytical planning approaches that focus on the assessment of risks, environmental attributes and cost characteristics of various portfolios. The approaches will be of the greatest value where they include assessments of the risks that could affect portfolio performance, including financial, market, environmental and other quantifiable and qualitative risks.
2. Appropriate approaches to constructing CDM ("Conservation and Demand Management") portfolios for inclusion in long-term plans. These approaches will be of the greatest value where they include established data on technical and achievable potential, costs, implementation barriers, sector specific characteristics, experience in implementation of CDM, and technology developments.
3. Assessments of different supply technologies and resources in the Ontario setting, including (but not limited to) natural gas generation, coal gasification, nuclear (new and refurbished), wind, biomass and hydro-electric resources. The assessments will be of the greatest value where they (1) utilize recent source information or current data on capital and operating costs, performance characteristics, technology life cycle, environmental impacts and any other relevant characteristics and (2) present

[1] http://www.powerauthority.on.ca/downloads/Supply_Mix_Web_Posting.pdf
[2] http://www.powerauthority.on.ca/downloads/Minister_Letter_to_OPA.pdf

data on a consistent basis across the supply technologies and resources that would be suitable for planning studies.

4. Appropriate methods to assess the impact on the natural environment of supply options. The methods will be of the greatest value where they are: (1) methodologically suited to long-term planning; (2) provide for identification and quantification of relevant environmental factors for assessment; (3) capture the cumulative environmental impacts; and (4) provide indications of the sustainability of options and supply mix plans.

The Power Workers' Union (the "PWU") objective is to provide information and advice to assist the OPA in developing a pragmatic, robust and sustainable power system plan that ensures Ontario has adequate, reliable, safe and reasonably priced electricity supply. This is essential for the continued economic prosperity and social welfare of the people of Ontario.

The PWU represents a large portion of the people working in Ontario's electricity industry and is keenly interested in the OPA's future resource plan, which will have a lasting and profound impact on the people of this province. A complete list of PWU employers is attached (Attachment 1). In addition, the PWU is a limited partner in the Bruce Power Limited Partnership.

The PWU experience provides a unique perspective of Ontario's electricity system. We are knowledgeable about the energy industry as a whole. We operate independent of government and employers. Our members form the industry's interface with the customers and are sensitive to customers' needs. Lastly, our families are energy consumers.

Our submission consists of eight additional sections:

- Section 2 assesses the OPA's responsibility for Ontario's future supply mix;
- Section 3 describes a supply policy framework;
- Section 4 analyzes the cost of the Government's coal-fuelled generation phase-out plan;

- Section 5 examines issues related to utilizing natural gas fired generation to replace existing coal facilities;
- Section 6 addresses the implementation of the supply policy framework;
- Section 7 provides input on encouraging conservation and energy efficiency;
- Section 8 provides input on assessing environmental impacts; and,
- Section 9 sets out the PWU's conclusion on the Government's coal-fuelled generation phase-out plan.

2 OPA'S RESPONSIBILITY FOR ONTARIO'S SUPPLY MIX

The OPA has the obligation to ensure Ontario's long-term supply adequacy. In meeting this obligation the OPA is responsible for forecasting the province's resource needs, and preparing an integrated system plan for conservation, generation and transmission. Section 25.2 (1) of the *Electricity Act, 1998* sets forth the following objects of the OPA:

> *(a) to forecast electricity demand and the adequacy and reliability of electricity resources for Ontario for the medium and long term;*
>
> *(b) to conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario;*
>
> *(c) to engage in activities in support of the goal of ensuring adequate, reliable and secure electricity supply and resources in Ontario;*
>
> *(d) to engage in activities to facilitate the diversification of sources of electricity supply by promoting the use of cleaner energy sources and technologies, including alternative energy sources and renewable energy sources;*
>
> *(e) to establish system-wide goals for the amount of electricity to be produced from alternative energy sources and renewable energy sources;*
>
> *(f) to engage in activities that facilitate load management;*
>
> *(g) to engage in activities that promote electricity conservation and the efficient use of electricity;*
>
> *(h) to assist the Ontario Energy Board by facilitating stability in rates for certain types of consumers;*
>
> *(i) to collect and provide to the public and the Ontario Energy Board information relating to medium and long term electricity needs of Ontario and the*

> *adequacy and reliability of the integrated power system to meet those needs.*

As a first step in the development of an integrated system plan, the Minister has requested the OPA to prepare a report on an Integrated Power Supply Plan. This task should be performed in a manner that is consistent with objective (b): *to conduct independent planning for electricity generation, demand management, conservation and transmission and develop integrated power system plans for Ontario* (emphasis added).

One implication of objective (b), which requires the OPA to engage in independent planning, is that the OPA must address supply issues in a rigorous analytical and non-politicized manner. As the OPA's mandate intends, it is essential for the OPA not to be constrained by the politics of the day. Ontario's future supply mix is a critical long-term issue and must be addressed through a reliable and sustainable long-term plan.

The Ontario Government announced a coal replacement plan during the summer of 2003. The plan was implemented without a complete and proper assessment of the costs and risks of such a significant decision. Appropriate planning, analysis and implementation assessment are required to ensure that the best informed decisions are taken. The public is entitled to know that the risks are being managed within acceptable boundaries. This is critical for a project that has such broad and deep implications for our economy and way of life.

That does not appear to have been the case for the coal shutdown decision. In the directive the Minister notes "It has been many years since a comprehensive, long-term plan for electricity has been prepared for the Province of Ontario, …" . The statement implies that long-term planning was not part of the decision-making process for the government's coal shut down policy.

The OPA's responsibility is to assess the new generation and transmission required to meet Ontario's current and future energy needs. It would be inconsistent with the OPA's mandate to accept the replacement of coal-fuelled generation as a binding constraint that must prevail regardless of the costs, benefits and risks that can be demonstrated through rigorous and independent expert analysis. Pursuing a coal replacement strategy, must be treated like any other government policy. Its fulfillment must be

tempered by economic, social and environmental realities—not politics. It would be irresponsible for the OPA to provide advice to the Minister that does not recognize that phasing-out coal, at a time when the province is in urgent need of new generation and transmission capacity may, unnecessarily place the province at risk of a serious generation shortfall.

Ontario's critical supply position was recognized in a statement made by the Premier on August 3, 2005 in Pontypool, Ontario when he indicated the people of Ontario will have to curb their consumption of electricity for at least two more summers before new generating capacity finally comes on line. This approach to energy planning is risky for the people of Ontario and the province's economy and industry. It is the OPA's responsibility to ensure that all options are considered so that a supply plan can be implemented that will keep the lights on in Ontario under all credible scenarios for future electricity demand; for example, pricing of natural gas as a generation source, construction delays, etc.

In assessing the future supply mix for Ontario, the OPA must balance its objectives, in particular the adequacy and reliability objective (a), and the cleaner energy sources objective (d), to ensure its supply mix plan is in the best long term interest of Ontarians. Minimizing emissions is not the sole objective. The OPA's consideration of the costs of environmental benefits must be based on rational analysis and an assessment of whether these costs can be translated into potential benefits of "investing" the same dollars in better ways (e.g. health care, cleaner generation technologies, energy efficiency, education, etc.).

In summary, to develop an integrated supply plan that ensures the future adequacy and reliability of Ontario's future electricity supply the OPA is obliged to carry out independent comprehensive assessments based on rigorous analysis of the benefits and costs. In addition, it must effectively balance the objectives set out in its mandate and consider appropriate mitigation options to address the risks identified in the analysis. This is the best way to ensure the supply plan is sustainable and in the best long term interest of the people of Ontario.

3 SUPPLY POLICY

In the PWU's view, for the continued economic prosperity and social welfare of the people of Ontario, the future supply for Ontario must be adequate and reliable, as well as safe, clean and priced at a reasonable cost. To meet this objective, a supply mix policy framework must ensure:

- Continued operation of existing generation for the remainder of their economic lives;
- A diverse mix of supply resources; and,
- Proper planning, rigorous analysis, and public consultation regarding any major changes to the manner in which Ontario's energy needs are met, including full compliance with the *Environmental Assessment Act*.

3.1 CONTINUED OPERATION OF EXISTING GENERATION

It is readily evident that the continued operation of existing generation assets—both nuclear and clean coal-- for the remainder of their economic lives will serve the goals of supply adequacy, reliability, safety and reasonableness of cost. These facilities are already sited and are linked to the grid. Skilled operating expertise and support operations are also in place. Substantial investments in clean coal technology have been made at some of these plants resulting in significant emission reductions. They also have a proven track record for providing reliable, low cost electricity to millions of Ontario homes.

Valuable generation assets such as these should not be prematurely written-off. If followed, this strategy will inevitably lead to increased public debt and higher electricity and natural gas prices. Analyses show that upgrading and rehabilitating existing generation is more cost effective than bringing new generation on line.

3.2 DIVERSE MIX OF SUPPLY RESOURCES

A diverse mix of supply resources reduces the risk that Ontario will become overly reliant on a single supply resource that may be uneconomic in the future. Ontario has already upgraded the vast majority of its existing hydroelectric generation and is pursuing the remaining opportunities. Energy security can also be maintained by continuing to use accessible and affordable uranium and coal supplies in North America. In addition, renewable generation technologies such as wind and solar power offer unique contributions.

Another promising opportunity is offered by biomass fuels such as wood pellets, straw and pelletized municipal waste. Ontario's forestry industry, agricultural sector and municipal waste streams offer unlimited supplies.

Experience around the world provides important lessons for Ontario. Utilities in Denmark and Germany are not only retrofitting their coal-fuelled generation with emission reducing technologies such as scrubbers and selective catalytic converters, but they are supplementing their use of coal by mixing in biomass fuels. For example, one plant in Denmark burns coal, heavy oil, natural gas, straw and wood pellets. The plant is equipped with NO_X and SO_2 abatement technology. The wood pellets are made from the waste generated at a plant that manufactures hardwood flooring. Some of their wood waste shortfall comes from pellets imported from Canada. At another plant both coal and straw are burned. Burning straw helps reduce emissions, including CO_2, and at the same time provides a new revenue stream for the agricultural sector. In both countries, coal-fuelled plants are using municipal waste in pellet form. This displaces coal and helps reduce waste streams to landfill sites.

European countries also offer some important lessons on the efficient use of thermal fuels. Their goal is to extract the maximum energy from whatever fuel is being used by producing electricity, heat for residential buildings and homes as well as cooling. Ontario needs to embrace this approach. Using biomass for electricity production would diversify our fuel mix which at the same time could help reduce the province's dependency on natural gas for residential heating, etc.

Conservation and efficiency initiatives are also a critical element in a diverse supply mix. However, unrealistic expectations will jeopardize future supply adequacy. As an illustration, while the Government has set a target for energy conservation to reduce peak consumption by 5 per cent by 2007, the IESO in its July 8, 2005 10-year outlook[3] has not reflected these targets in its Ontario demand forecast. The IESO states that its reason for doing so is that "the impact of new conservation initiatives is as yet difficult to forecast".

International experience points to a clear lesson: the future supply mix recommended by the OPA should recognize the value of flexibility to accommodate evolving technologies and opportunities. Diversity should be encouraged, not constrained, so that Ontario is not overly reliant on particular technologies that could place Ontario at a competitive disadvantage in the energy marketplace.

3.3 PROPER PLANNING AND COMPLIANCE WITH ENVIRONMENTAL ASSESSMENT ACT

Policy on supply mix should ensure proper system planning and a full and comprehensive environmental assessment of the proposed plan preceding any final decision on the plan. In implementing a resource plan, the Government is required under the *Environmental Assessment Plan Act* to conduct an environmental assessment that looks at Ontario's electricity needs, all available resource options, and alternative methods of implementing each option preceding individual decisions to add generation facilities. Implementing a supply plan in the absence of such an assessment is likely to result in haphazard and ill-conceived decisions that put Ontario's long-term supply adequacy, reliability, safety and reasonableness of price at risk.

[3] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

4 COST OF PHASING-OUT ONTARIO'S COAL-FUELLED GENERATION

As noted above, the Ontario Government introduced a coal phase-out plan without it being supported by planning or analysis in the context of a comprehensive long-term supply plan. Without an integrated, rational assessment of all available options, Ontarians have no assurance that the best-informed decisions have been made; that risks are within acceptable boundaries; and that appropriate risk mitigation is in place.

In this section, the market price and cost impacts of replacing coal-fuelled generation with gas-fired generation ("coal closure") as compared to operating coal-fuelled stations retrofitted with clean coal technology ("clean coal") is assessed. In doing so, the electricity market and generation costs (e.g., cost of generating electricity; investment in new capacity; cost of installing emission controls on coal-fuelled units; and differences in import and export of electricity), as well as incremental gas infrastructure and variable costs (e.g., gas transportation, storage capacity, operational flow orders, monthly imbalance penalties, and gas price volatility) are examined. The impact on market reserves, imports, and emissions are assessed, and a risk assessment on gas forecast and load growth is provided. Comment is also provided on the consideration for CDM programs and on assessing environmental impacts as requested in the OPA's Call for Submissions.

4.1 MARKET AND COST ASSESSMENTS

The PWU retained Global Energy Advisors (Global) to compare the cost impact of coal closure to the impact of clean coal[4]. In the coal closure supply scenario, all coal-fuelled stations are closed and replacement plants consisting of gas-fired and renewable resources, rehabilitation of nuclear units, and imports from Manitoba and Labrador are brought on line in accordance with the IESO's July 8, 2005 10-year outlook supply

[4] Draft Confidential Global Energy Decisions Report Prepared for the PWU. Market Analysis of the Future Supply Mix for Ontario. August 23, 2005.

forecast[5]. In the clean coal case, coal-fuelled stations retrofitted with state of the art clean coal technology[6] are kept operational, and gas-fired generation currently under construction, renewable resources, rehabilitation of nuclear units, imports from Manitoba and Labrador, and new clean coal generation is brought on line. In the coal closure case, most of the retired coal-fuelled generation is replaced by gas-fired generation. Descriptions of Global Energy's resource scenarios are provided in Tables 4-1 and 4-2.

Table 4-3 shows the gas price scenario used in Global Energy's analysis. Global points out that there is substantial uncertainty related to natural gas price forecasts. Gas forecast uncertainty is addressed in detail in section 5.2. Global also notes that its model does not include the effects of natural gas and electricity price volatility. Given current electricity demand, the IESO's high growth load scenario appears to be more realistic than its medium growth scenario and the demand scenario used in Global Energy's analysis reflects the IESO's high growth scenario as shown in Table 4-4. The load forecast is addressed further in the risk assessment section. Global Energy's coal closure market price impact therefore is conservative and it is possible that actual impacts could be significantly higher.

Global Energy's cost analysis conducted for the PWU estimates the average cost of generation at net present value to be $11 billion, or $9.50/MWh higher in the coal closure case when compared to the clean coal case. Figure 4-1 shows the annual spread in cost of generation between coal closure and clean coal over the planning period. Capital costs and operational characteristics for new capacity entering the market used in Global Energy's analysis are shown in Table 4-5.

[5] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

[6] Note: The clean coal technologies are wet lime scrubbers to control SO_2 and selective catalytic reduction technology to control NO_x emissions.

Table 4-1: New and Rehabilitated Resources for 2005-2017

Resource Type	Project Name	Fuel Type	Capacity MW	Estimated On Line Date	Global Energy's On Line Date	Included in Clean Coal Case?	Comment
Committed and Contracted Resources	Pickering Unit 1	Uranium	515	2005-Q3	9/1/2005	Yes	
	Greater Toronto Airports Authority	Gas	117	2005-Q4	10/1/2005	Yes	RFP
	Melancthon Grey Wind Project	Wind	68	2005-Q4	12/1/2005	Yes	RFP
	Kingsbridge Wind Power Project	Wind	40	2005-Q4	10/1/2005	Yes	RFP
	Prince Wind Farm	Wind	99	2006-Q1	3/1/2006	Yes	RFP
	Erie Shores Wind Farm	Wind	99	2006-Q2	4/1/2006	Yes	RFP
	Loblaws Properties	Demand	10	2006-Q2	4/1/2006	Yes	RFP
	Blue Highlands Wind Farm	Wind	50	2006-Q3	7/1/2006	Yes	RFP
	Umbata Falls Hydroelectric	Water	23	2007-Q1	1/1/2007	Yes	RFP
	Greenfield South Power Project	Gas	284	2007-Q4	11/1/2007	No	Approved by Ontario Govt.
	Greenfield Energy Centre	Gas	1,015	2007-Q4	11/1/2007	No	RFP
	St. Clair Power	Gas	688	2008-Q1	1/1/2008	No	RFP
	Greenfield North Power Project	Gas	330	2009-Q2	4/1/2009	No	Approved by Ontario Govt.
Additional Resources	Downtown Toronto Additional	Gas	500	2008	1/1/2008	No	
	Western GTA	Gas	1,000	2008	1/1/2008	No	
	Cogeneration	Gas	500	12/31/2007	12/31/2007	No	Lambton replacement
	Cogeneration	Gas	500	2008	12/31/2008	No	Nanticocke replacement
	Bruce Units 1&2	Uranium	1,538	2009	1/1/2009	No	
	Pickering Unit 2	Uranium	515		12/1/2006	Yes	Not include in Base Case due to cancellation notice 8/12/05
	Pickering Unit 3	Uranium	515		12/1/2007	Yes	
	Mattagami Expansion	Hydro	380	2009	1/1/2009	Yes	
Repowering	Thunder Bay Replacement	Gas	306	12/31/2007	12/31/2007	No	Conversion of Coal
Energy Conservation	5% Target	Demand	1,350	2007			Excluded- Not Certain
RFPs	Renewable Energy RFP II (April 2005)		1,000	2007	1/1/2007	Yes	5% by 2007 Ren Targets
	Renewable Energy RFP III (July 2005)		200	2007	1/1/2007	Yes	5% by 2007 Ren Targets
Renewable Targets	10% by 2010 (2700 MW)		765	2010	1/1/2010	Yes	Adjusted for RFPd resources
Imports	Manitoba Hydro		1,500		1/1/2017	Yes	
	Labrador		670		1/1/2013	Yes	
Total			14,576				

Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Table 4-2: Additional Resources

	Base Case (MW)			Clean Coal Case (MW)			
Year	Natural Gas	Nuclear	Wind	Natural Gas	Nuclear	Wind	Coal
2006-2011							
2012			100			100	
2013			50			50	
2014	425		100			100	
2015	1,520						500
2016	605			360			
2017				180			
2018				180			
2019				360			
2020				180			500
2021		1,000			1,000		
2022			500			450	
2023	180		200	245		150	
2024	180		100			100	
2025	245			540		100	
TOTAL	3,155	1,000	1,050	2,045	1,000	1,050	1,000

Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Table 4-3: Gas Price Scenario ($/MMBTu)

Year	Henry Hub (C$/MMBtu)	Ontario (C$/MMBtu)
2006	10.07	10.71
2007	8.93	9.56
2008	7.91	8.52
2009	7.07	7.68
2010	7.24	7.86
2011	7.14	7.76
2012	7.09	7.7
2013	7.14	7.76
2014	7.22	7.84
2015	7.27	7.89
2016	7.23	7.85
2017	7.25	7.87
2018	7.32	7.94
2019	7.41	8.03
2020	7.49	8.11
2021	7.53	8.16
2022	7.54	8.17
2023	7.56	8.19
2024	7.60	8.23
2025	7.64	8.28

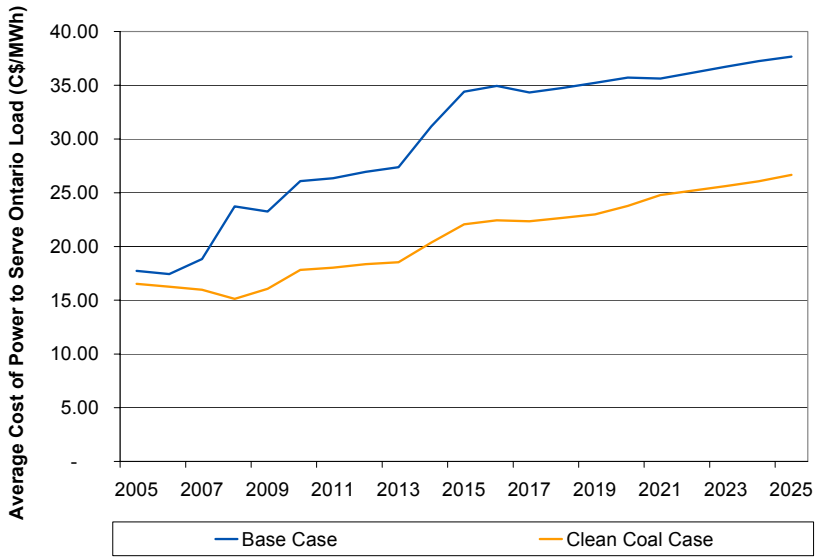
Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Table 4-4: Annual Energy Demand and Growth Rate Scenario

Year	Annual Energy Demand (GWh)	Electricity Demand Growth (%)
2006	160,418	
2007	161,947	0.95%
2008	164,239	1.42%
2009	165,572	0.81%
2010	167,515	1.17%
2011	169,587	1.24%
2012	171,876	1.35%
2013	173,428	0.90%
2014	175,390	1.13%
2015	177,297	1.09%
2016	178,835	0.87%
2017	180,378	0.86%
2018	181,961	0.88%
2019	183,541	0.87%
2020	185,139	0.87%
2021	186,791	0.89%
2022	188,406	0.86%
2023	190,067	0.88%
2024	191,789	0.91%
2025	193,424	0.85%

Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Figure 4-1: Comparison of Cost of Serving Ontario Load



Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Table 4-5: Capital Costs and Operational Characteristics, New Generation

Unit Characteristic	Combustion Turbine	Combined Cycle	Pulverized Coal	Wind	Nuclear
Installation Years	2005-2028	2005-2028	2005-2028	2005-2029	2005-2029
Capacity (MW)	160 Apr-Sep 180 Oct-Mar	250 Apr–Sep 230 Oct-Mar	500	100	1000
Full Load Heat Rate Average Degradation (HHV, Btu/kWh)	10,500	6,800	9,540	N/A	10,500
Fixed O&M (2004 C$/kW-year)	12.70	12.70	30.48	12.00	75.60
Variable O&M (2004 C$/MWh)	5.06	2.53	3.84	7.20	0.60
Forced Outage Rate (applies to all hours) (%)	2.0%	2.0%	6.0%	N/A	7%
Maintenance Outage Rate (MOR) (%)	5.0%	5.0%	7.0%	N/A	8%
Overnight Construction Cost (2004 C$/kW)	508	755	1,434	1,680	2,400

Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

The PWU also asked Global to provide an assessment of fixed and variable gas–related costs for new gas-fired generation. Global Energy's description of the assumptions used in this analysis is provided here. Global based the analysis on fuel consumption data that exclude Pickering Units 2 and 3. Between 2015 and 2020, the average annual gas usage was approximately 250 Bcf/yr, 60 percent load factor, and 7,330 Btu/kWh heat rate. These numbers were proportionately adjusted for 100 percent load factor and readjusted for the 90 percent load factor. Global notes that these annual load factor levels will be slightly lower during actual operation due to plant outages for planned events such as maintenance and unplanned events. The maximum daily quantity was 1,141,533 Mcf/d for all annual load factors based on the assumption that no transporter would allow rate acceleration from the 4.17 percent hourly ratable take (i.e., no 6.25 percent hourly ratable take). Global also notes that July is the peak month and that 2018 is the peak year with a 72 percent annual load factor.

Weighted average costs for five selected transportation routes were used based on 50 percent weighting of one route for redelivery through the Enbridge LDC and 50 percent weighting of four routes for redelivery through Union (or 12.5 percent for each Union-related route). The fixed costs for transportation were estimated by using existing tariff rates for the needed Maximum Daily Quantity (MDQ). No potential partial recovery of these fixed costs are included as a result of short-term release of capacity and of basis differentials being greater than volumetric costs (commodity charge plus fuel retention).

Incremental costs for expansion and extension capacity were based on the assumption that 25 percent of the existing aggregated transportation capacity would be upgraded at a cost equal to 40 percent of existing rolled-in rates for non-compression capacity (looping, metering, laterals, etc.) and, for compression capacity (8,500 H.P.), a cost equal to $50,000 U.S./Mmcf/d. These costs exclude any upstream fuel retention.

The fixed costs for LDC transportation and storage capacity were estimated using existing tariff costs. The storage capacity cost was based on an estimated volume equal to 10 percent of the MDQ, assumed sufficient for peak-day load shaving and seasonal load following. The fixed-cost capacity components of the tariffs for long-haul and LDC

transportation (and storage) capacity are not included in the price forecast for electrical energy, only regional basis differentials that are treated as volumetric costs.

The variable costs for Operational Flow Orders (OFO) and monthly imbalance penalties on the long-haul transporters and the LDCs were based on the assumption that the imbalance volume equal to 10 percent of the MDQ would occur five and three times a year for the OFO and monthly imbalances, respectively. These penalties are based on the 2018 projected regional hub prices (in 2005 dollars) and exclude any upstream fuel-retention costs. These costs are not included in the price forecast for electrical energy.

The incremental cost of increased price volatility at the Dawn Hub, due to this additional gas demand and its seasonal distribution, has been estimated using historical basis differentials (Dawn minus Henry Hub), the historical affect of Alliance Pipeline on TCPL basis differentials and rate design, and on the Vector Pipeline utilization rate, and the estimated long-term seasonal dispersion of natural gas prices at the Henry Hub.

According to Global Energy's analysis, the incremental gas fixed and non-energy variable costs related to the incremental gas infrastructure costs, adds costs at net present value as high as $3 billion to the cost of coal closure. Further discussion on incremental gas infrastructure is provided in section 5.1.

The break down of the incremental gas fixed and non-energy variable costs under 100 per cent, 90 and 60 per cent load factor are shown in Table 4-6. While explanatory notes are provided in Table 4-7, further details on gas infrastructure are provided in section 5.1.

4.2 RESERVES

Under the resource scenario used in Global Energy's analysis, reserve capacities are lower with coal closure for the first half of the 2005-2025 planning period. The difference narrows in the latter half of the planning period as new generation is added.

Table 4-6: Summary of Estimated Incremental Gas Fixed and Variable Costs[7]

	Unit Cost						Annual Cost			
	Canadian $ Per MMBtu			Canadian $ Per MWh			Million Canadian $			
	Annual Load Factor (%)			Annual Load Factor (%)			Weighted Average			Range (Not Additive)
	100	90	60	100	90	60	100	90	60	
Fixed Cost Category										
1. Existing long-haul Transportation Capacity	1.10	1.22	1.83	7.68	8.65	13.40	457	457	457	260-653
2. Incremental long-haul Transportation Capacity										
• Non Compression	0.11	0.12	0.18	0.77	0.87	1.34	46	46	46	26-65
• Compression	0.04	0.05	0.07	0.29	0.32	0.50	17	17	17	17-17
• Subtotal	0.15	0.17	0.25	1.06	1.19	1.84	63	63	63	-
3. Subtotal Long-Haul Transportation Capacity	1.25	1.39	2.08	8.74	9.84	15.24	520	520	520	-
4. LDC Transportation Capacity	0.20	0.22	0.33	1.37	1.55	2.39	81	81	81	31-145
5. LDC Storage Cost	0.01	0.01	0.02	0.08	0.09	0.13	5	5	5	5-5
6. LDC Incremental Transportation/Storage Capacity	0.02	0.02	0.03	0.15	0.16	0.26	9	9	9	4-15
7. Subtotal LDC Capacity	0.23	0.25	0.38	1.60	1.80	2.78	95	95	95	-
8. Subtotal Fixed Cost	1.48	1.64	2.46	10.33	11.64	18.02	615	615	615	468-900
Variable Cost Category										
1. OFO Penalties	0.04	0.04	0.06	0.26	0.30	0.46	16	16	16	7-55
2. Monthly Imbalance Penalties	0.02	0.02	0.03	0.13	0.15	0.23	8	8	8	6-12
3. Incremental Volatility Cost	0.50	0.40	0.35	3.50	2.84	2.57	208	150	87	87-208
4. Subtotal Variable Cost	0.56	0.46	0.44	3.89	3.28	3.26	232	174	111	102-268
Total Cost (Fixed and Variable)	**2.03**	**2.10**	**2.90**	**14.22**	**14.92**	**21.28**	**847**	**789**	**726**	**595-1127**

[7] Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

Table 4-7: Notes to Table 4-6

1.) The M-7 rate schedule was used for transportation on the Union Gas LDC system. The T-1 Union Gas LDC transportation rate schedule would likely be used by most generators in Union's franchise. The additional cost of the T-1 service (vs M-7) is approximately C$0.25/MMBtu at a 65 percent annual load factor, or about C$0.12-0.13/MMBtu when weighted to reflect this report's gas pipeline routing assumptions. At 100 percent annual load factor, the latter number would be approximately C$0.08/MMBtu.

2.) The current analysis assumes the same maximum daily quantity (MDQ) of gas for upstream long-haul transportation and downstream LDC transportation. A more accurate estimate would have the downstream LDC's MDQ at 1.4x MDQ and the upstream long haul at 1.0x MDQ. Therefore, the 10 percent of the MDQ used for Table 4-3 results would then be estimated at approximately 1.15x MDQ. This would increase the costs in Table 4-3 by approximately C$0.01/MMBtu (100 percent annual load factor).

3.) Storage pricing could move to market based rates by the time the gas-fired generators come on stream. These market-based rates could be 50 percent high deliverability (10 percent) and 50 percent low deliverability (1.2 percent) and range in demand cost from a low of C$1.50/GJ and a high of C$3-4/GJ, an average of C$2.50/GJ assuming 50/50 weighting. The current analysis (summarized in Table 4-3) assumes higher cost-of-service storage demand rates of approximately C$3-3.50/GJ.

4.) The five gas pipeline routes selected for this analysis reflect bringing gas supply from various producing regions- Western Canadian gas (via TCPL), U.S. Mid Continent gas (via ANR), and U.S. Gulf Coast gas (via ANR). The Alliance Pipeline was not included in the routing analysis. If Alliance/Vector was substituted for ANR/Vector to Dawn, the additional cost would be roughly C$0.60/MMBtu of demand costs, or C$0.08/MMBtu on a weighted basis.

5) The current analysis assumes all gas deliveries to Enbridge Gas come from the "north" (via TCPL from Empress to its Eastern Zone). It is estimated 75 percent of the TCPL gas would come from the "south" (via the Great Lakes or Vector, to Dawn, redelivery on Union to Parkway, and Parkway to Enbridge Gas on TCPL). An estimated 35 percent of this gas would also incur in/out toll charges for Tecumseh storage (owned by Enbridge). The incremental cost for this additional gas routing would be approximately C$0.20/MMBtu and C$0.07-0.08/MMBtu when weighted for its share of the total gas supply.

Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

4.3 IMPORTS

Global Energy's analysis prepared for the PWU indicates that coal closure increases Ontario's dependence on other jurisdictions for electricity compared to clean coal. The IESO's supply overview as shown in Table 4-8, indicates that Ontario has been a net importer of electricity in all but one year since 1998. From Ontario's supply perspective, it would appear that closing down economically and operationally viable generation is not an option. Rather, to address Ontario's supply shortage all existing generation

should be kept operational to move the province towards self-sufficiency. While nuclear outages and relatively low hydro production have contributed to the need for imported power in the past, there is no guarantee that this will not be the case in the future. Ontario's coal-fuelled stations need to be kept operational to effectively address this risk even with the planned generation additions identified by the IESO. As addressed later in this submission, the IESO has identified major risks associated with the in-service schedule of the planned additional generation. One such risk has materialized with the recent announcement of the cancellation of the 330 MW Greenfield North project.

Table 4-8: Ontario Imports and Exports

Year	Imports (TWh)	Exports (TWh)	Net Imports (TWh)
2004	9.8	9.5	0.3
2003	10.4	6.3	4.1
2002	7.1	3.9	3.2
2001	4.3	4.1	0.2
2000	5.1	5.5	-0.4
1999	6	4	2
1998	6	3	3
1997	3.8	6.4	-2.6

Source: IESO Supply Overview Web Page[8]

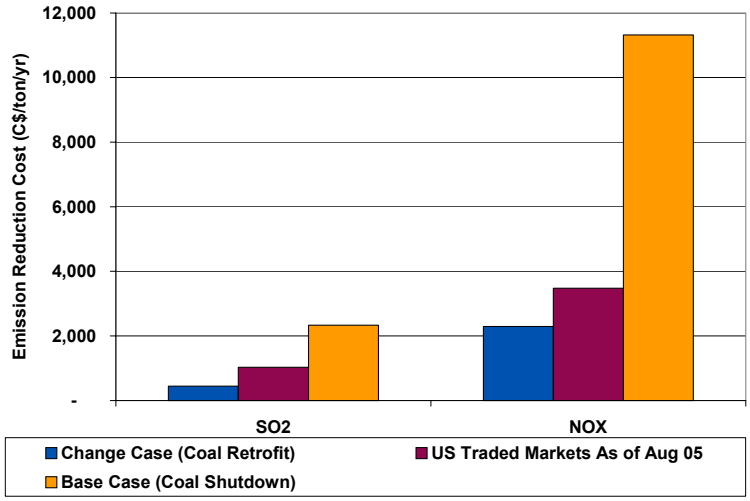
4.4 EMISSIONS

With regard to emissions, Global Energy's analysis prepared for the PWU indicates that coal closure compared to clean coal is an expensive solution to reducing NO_x and SO_2 emissions with the costs per ton of emissions reduced in the coal closure case at about more than four times the cost in the clean coal case. Assuming clean coal technology can reduce NO_x and SO_2 emissions by 80 per cent, Figure 4-2 shows that clean coal achieves more than 80 per cent of the coal closure emission reductions at less than 20 per cent of the cost. Figure 4-2 also shows that the cost of emission reduction in the

[8] http://www.ieso.ca/imoweb/media/md_supply.asp

clean coal case is lower than the current price of the U.S. emission allowance for NO_X and SO_2. Much of Ontario's pollution comes from emission sources in the U.S. Therefore, while U.S. generating plant emissions are forecast to decline during 2005-2025, they will not be reduced by as much as Ontario generating plant emissions and will continue to impact Ontario's air quality, with Ontario's growing dependence on electricity imports from the U.S. likely worsening Ontario's air quality.

Figure 4-2: Comparison of Emission Reduction Cost



Source: Global Energy Decisions Confidential Draft Report to PWU, August 23, 2005

4.5 *RISK ASSESSMENT*

4.5.1 DEMAND

The IESO[9] states that normal weather peak demands are expected to increase from about 24,200 MW in 2006 to 26,900 MW in the summer of 2015. On July 13, 2005 maximum hourly Ontario demand was already at 26,160 MW and total use was 52.5 GWh. Although weather has been substantially warmer than normal, peak design day

[9]IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015

conditions do not appear to have existed on days when overall Ontario demand record levels have occurred. Had more extreme weather closer to peak summer weather conditions occurred, the demand levels in Ontario and the consequences would have likely been more severe than illustrated.

4.5.2 SUPPLY

The IESO's supply overview indicates that Ontario has been a net importer since 2001. Closure of a dependable supply source in the absence of proven reliability of replacement generation adds substantially to Ontario's supply risk.

4.5.3 TRANSMISSION

In addition to the increased generation costs, and incremental gas infrastructure and variable costs, there are substantial transmission cost increases related to 13 major transmission projects identified by the IESO[10] as required to maintain system reliability with coal closure. As well, there will be increases in gas price levels and volatility for gas consumers related to the incremental gas demand created by gas-fired generation. This is discussed further in section 5.2.

4.5.4 LOSS OF SKILLS AND FUEL CONTRACTS

Critical operating skills will be lost if the coal plants are closed. If for some reason there is a need to return any of these closed plants to service for system reliability reasons Ontario won't have the operators. As well, with the plants scheduled for closure, the plants will no longer be able to benefit form long-term contract arrangements with fuel suppliers. Instead they will be subject to more expensive short-term supplies. In the event that there is a need to return a plant(s) to service, most of the units will not have been retrofitted with clean coal technology.

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[10]IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015

4.6 SUMMARY ON COST OF PHASING-OUT ONTARIO'S COAL-FUELLED GENERATION

Coal-fuelled generation closure results in:

- Higher generation costs amounting to a net present value of about $11 billion, or $9.50/MWh higher than in the clean coal case, and incremental gas fixed and variable costs at net present value of $3 billion, or annual cost of $726 million at 60 per cent load factor, for total estimated costs of closing coal plants at net present value of $14 billion that would be avoided in the clean coal case;
- Ontario becoming more dependent on other jurisdictions for supply;
- Ontario becoming reliant on natural gas and its substantial supply and pricing uncertainty for its electricity supply, which can be abated with clean coal;
- Higher gas prices for all Ontario gas users;
- Lower reserve margins relative to the clean coal case;
- A substantially more costly scenario for reducing NO_x and SO_2 emissions compared to clean coal, which reduces 80 per cent of the coal closure case's NO_x and SO_2 emissions at 20 per cent of the cost. In addition to which the emission reduction costs in the clean coal case are less than the price of US emission allowances for NO_X and SO_2.

5 NATURAL GAS ISSUES

There are substantial uncertainties concerning natural gas. These include the availability and price of imported LNG and domestic gas; electricity generation and industrial demand; and the need for additional infrastructure.

5.1 NATURAL GAS INFRASTRUCTURE COSTS

5.1.1 GAS-FIRED GENERATION INFRASTRUCTURE

Replacing coal-fuelled generation with gas-fired generation raises the immediate issue of the timely construction and in-service dates of generation infrastructure required to implement the government's supply plan. The IESO notes that timely decisions on generation projects representing more than 9,000 MW currently in various stages of discussion, development, or negotiation will be key to addressing the shortfalls that will occur with the coal generation phase-out[11]. Also of critical importance will be setting and meeting the in-service dates. The IESO's coal phase-out supply picture shows a critical transition phase in 2007-2009 that includes four of the most advanced supply projects out of eight projects under discussion, development or negotiation to provide 9,000 MW of additional generation. These will barely meet the median required resource level and falls short of the high required resource level. In 2011, this supply scenario fails to meet the province's median required resource level and in 2013, it is insufficient to meet even the low required resource level.

Ontario consumes approximately 1,000 BCF of natural gas a year of which 250 BCF is consumed by 2.4 million residential customers. To replace 7,500 MWs of coal-fuelled generation with an equivalent natural gas-fired generation requires 200-300 BCF of natural gas. This represents a 30 per cent increase in Ontario's annual natural gas

[11] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015

consumption representing unprecedented growth in natural gas demand. Such growth in turn requires major investment in new natural gas capital infrastructure including upstream transmission, downstream transmission, distribution, storage, meters and regulation, to provide gas service to new gas-fired generators. The earliest normal construction, realistically, for all of the 7,500 MW of replacement generation, would be end 2009 and more likely end 2010. Specialized services to large gas-fired generators (e.g., computing capability, new dispatch rules and services, new cost allocation procedures) will need to be designed, approved by the Ontario Energy Board (OEB), and implemented in time to meet the 2009 time line.

It is apparent then, that planning on replacing 7,500 MW of coal generation with gas-fired generation by early 2009 is not practical.

Rigorous risk mitigation measures and controls will be necessary to address the high level of uncertainty and the severity of the consequences of supply shortages. Given the risks identified by the IESO, there is no doubt that the coal phase-out scenario indicates a precarious future supply scenario for Ontario. To phase-out coal-fuelled generation and attempt to make what the IESO describes as the "largest and most significant change" to the province's electricity system within an unreasonable time frame that puts at risk the adequacy and reliability of this essential energy supply, is irresponsible. With all the risks identified by the IESO, it is a flawed plan that is deleterious to the economic and social welfare of the people of this province.

5.1.2 Cost Benefit of Replacement of Coal-fuelled Generation

DSS Management Consultants Inc. and RWDI Air Inc. ("DSS") prepared a cost benefit study on the replacement of Ontario's coal-fuelled electricity generation for the Ontario Ministry of Energy that was released in April 2005. Highlights of the cost benefit of

replacing coal-fuelled generation are presented here through a review of the DSS study conducted for the PWU by ERA[12].

The DSS study covers the following four scenarios:

- Scenario 1 – Base Case, is the status quo and continues the operation of coal-fuelled generation with the current regulatory emissions caps.
- Scenario 2 – All Gas, produces all of the replacement electricity through new natural gas-fired generation.
- Scenario 3 – Nuclear/Gas, produces all of the replacement electricity through a combination of refurbished nuclear and new gas generation facilities.
- Scenario 4 – Stringent Controls, continues operating the coal-fuelled generators with the installation of new emission control technology.

With primary emphasis on estimated health and life savings considerations, the DSS study suggests that Scenario 3, replacement of coal-fuelled generation with combined nuclear and natural gas generation yields the greatest net benefit of the four scenarios.

ERA found that the DSS study grossly underestimates the gas costs in all gas-fired generation scenarios. The DSS study did not provide sufficient background detail to allow for an assessment of the statistical analysis used to weight the various gas price scenarios and was found to seriously lack factual gas pricing data.

The causes of the underestimation of the gas costs are summarized as follows:

- The gas price forecast underestimates the delivered price of gas by more than 30 per cent, resulting in an underestimate of $1.2 billion/year throughout the 22 year forecast period (2005-2026).
- A significant underestimate of the capital cost for new gas infrastructure to deliver gas to new gas-fired generators from the gas production zones to the new

[12] Elenchus Research Associates. Confidential Review of DSS Management Consultants Inc. and RWDI Air Inc. April, 2005 Report prepared for Ontario Ministry of Energy on Cost Benefit Analysis of Replacing Ontario's Coal-fuelled Electricity Generation. May 10, 2005.

generators' sites in Ontario, resulting in an underestimate in the range of $1.1 - $1.3 billion in total capital costs.

- The use of 6,447 MWs of capacity taken out of service rather than 7,500 MWs, which understates the gas costs and overstates the benefits.
- The lack of an estimate of the impact of the large new gas loads on the price of gas for existing Ontario gas users, resulting in an underestimate of incremental cost between $0.7 and $1.4 billion/year.

With appropriate adjustments for the gas price forecast and capital cost for new gas infrastructure alone, the DSS study's Scenario 4, the continued operation of coal-fuelled generators retrofitted with new emissions control technology, provides the lowest cost scenario at $2.8 billion/year compared to the cost for the DSS study's Scenario 3, refurbished nuclear combined with gas, at $3.5 billion/year.

ERA's review identifies a number of significant issues related to natural gas generation as a replacement for coal-fuelled generation in Ontario that need to be part of the OPA's considerations on Ontario's future supply mix to ensure comprehensive consideration of risks. Consideration of the issue of capital costs as described by ERA is presented here.

Capital Costs

ERA estimates a total capital cost for new gas infrastructure including transmission, distribution, storage, meters and regulation under optimal conditions to range between $700 million to $1.4 billion compared to the estimate of $210 to $310 million for the distribution costs included in the DSS study. Under less preferred conditions where the Ontario Government requires speedy gas infrastructure construction the costs could be as high as the $3 billion projected by Global Energy. In coming up with its estimate the following requirements for new gas infrastructure were identified:

- **Union Gas Dawn to Parkway Capacity** – New high pressure transmission capacity to move gas from the primary Ontario hub at Dawn, located southeast of Sarnia, to the west side of Toronto for a substantial portion of the 7,500 MW of replacement generation will be required. The amount of new capacity depends on the nature and location of upstream deliveries to Ontario as well as the

location of the new gas-fired generators. Based on a recent filing made to the OEB that reflected a $387 million cost to expand the Dawn to Toronto system[13], a range of $350 to $400 million is suggested as a reasonable estimate for this project.

- **In Ontario Storage Facilities** – Incremental storage and changes to existing storage operations to provide hourly, daily and seasonal load balancing services to manage the gas-fired generators' load variation will be required. The new storage facilities will require high deliverability capability to handle the rapid change in gas requirements related to the hourly and seasonal changes in generators' loads. This could also require substantial investment in compression and new incremental storage, valves and pipelines to allow for movement of gas between storage facilities and between Enbridge's Tecumseh Storage operations and Union's Dawn facility. The cost for these facilities is estimated at $50-75 million.

- **In Ontario Distribution Service** - An example of the costs associated with the distribution system is illustrated by looking at the costs associated with supplying the Nanticoke site. For the Nanticoke facility, gas would move along the Dawn to Parkway line and then south to the Nanticoke facility. This requires expansion of the Dawn to Parkway line and a major expansion of the distribution line to Nanticoke at an estimated cost of $200 to $250 million. Given the size of the Nanticoke facility and the significant distance between the Nanticoke site and Dawn to Parkway transmission line, to be prudent, it is suggested that a secondary feed from the TransCanada PipeLines line in the Niagara region be provided to ensure that the facility could continue to stay in service in the event that the primary feed on the Nanticoke line was ever disrupted.

- **In Ontario Metering and Regulation** – Each new generator will require new metering and regulation at the generator site. These costs are estimated at

[13] OEB proceeding EB-2005-0201 Section 5, Schedule 10, Line 18.

approximately $10 to $20 million depending on the size and number of generators.

- **Upstream Infrastructure for Gas Transmission and Storage** - A substantial increase in upstream high-pressure pipeline capacity will be required to bring incremental gas from the production zones (both in Canada and the US). The current eastern deliverability of about 6 BCFD would need to be increased to 6.8 – 7.0 BCFD at an estimated cost in the area of $0.75 billion depending on the expansion route. In hand with this large increase in upstream capacity, upstream storage would also likely need to be expanded.

ERA estimates the total potential capital cost in the range of $1.36 to $1.55 billion as shown in Table 5-1.

Table 5-1: Estimated Capital Cost for New Gas Facilities

Dawn to Parkway Transmission & Compression	$350 - $400 million
Ontario Distribution, Storage, Transmission, Metering and Regulation Facilities	$260 - $400 million
Upstream Infrastructure	> $750 million
Potential Total Cost	**$1,360 - $1,550 million**

The PWU strongly supports the Government's efforts to develop and maintain a clean environment but is concerned that the people of Ontario have not been provided with an accurate picture of the costs, alternatives to and risks associated with replacing coal-fuelled generation.

The DSS study's cost benefit analysis of replacing Ontario's coal-fuelled electricity generation is questionable by virtue of its use of critically flawed natural gas price and infrastructure assumptions.

Putting coal on hold results in continued emissions at current levels for a longer period if gas infrastructure is not in place in time for coal phase-out by early 2009 and emission improvements that could have been made will not have been made.

5.2 NATURAL GAS PRICING DYNAMICS

5.2.1 NATURAL GAS PRICING DYNAMICS

The price of natural gas is likely to be the most significant single determinant of the impact that coal closure will have on the market price of electricity. Substantial uncertainties that affect the future supply of natural gas include the availability and price of imported LNG and domestic gas, and electric and industrial demand for natural gas that require additional pipeline system investments.

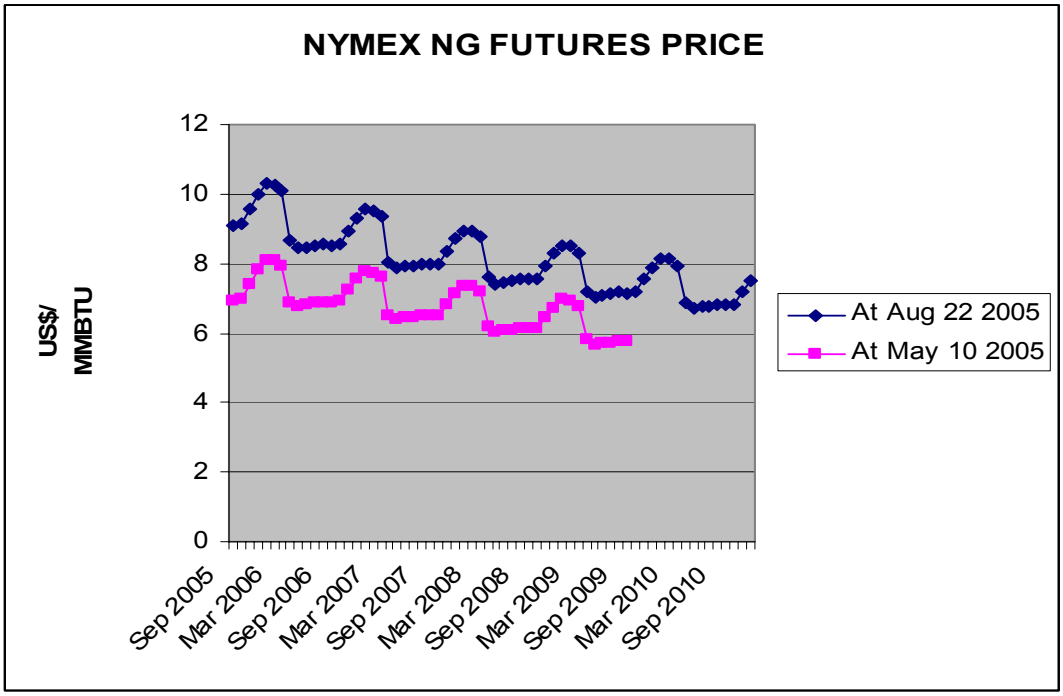
The current price of natural gas is very high by historical measure. Some forecasters have indicated that they expect a significant decline in natural gas pricing in 2008-2009 followed by modest rises. Their view is that the current high price levels are temporary and will moderate followed by a gradual rise over the longer term. Other gas and crude oil forecasters hold the view that gas and crude oil prices have entered a new era of pricing, that the changes in pricing are driven by structural, not cyclical, changes. A recent forecast by AJM[14] shows a modest decline followed by a rising price trend.

Current NYMEX forward prices and option contracts are at historical high levels as shown in Figure 5-1. This chart shows the forward price as determined on May 10, 2005 and also on August 22, 2005. The difference between the curves illustrates the significant rise since May 10, 2005 in the base price level underpinning the forward markets.

Current option contracts for crude and natural gas have very large open interests for the October 2005 contract with prices for crude oil at $100/BBL and natural gas in the $12-$14/MMBTU range. These are unusually high price levels and unusual contract volumes at these price extremes.

[14] http://www.nymex.com/ng_fut_pso.aspx http://www.ajma.net/pricefore.htm (see June 30, 2005 link)

Figure 5-1



Why Are Prices Behaving Like This?

Energy price forecasts are a critical component of major investment decisions and supply mix planning and policy development. Given that most policy and investment decisions are long-term and significant capital is required, it is essential that alternative pricing scenarios be considered in the supply mix planning process. The risk of being wrong, if you assume that price will go to the downside, is detrimental given the length of time to recover and transition into other fuels or adjust lifestyle.

The following summary from *The End of Cheap Oil: Cyclical or Structural Change in the Global Oil Market?*[15] provides the rationale for why the current prices are a structural change.

> *"There is no doubt that oil markets have changed significantly in recent years. This is evident in the direction and in the volatility of crude oil and product prices seen over the past five years and in particular the period since 2003. The gradual tightening of the oil supply chain had been observed for some time but it was only in*

[15] Herman Franssen. *The End of Cheap Oil: Cyclical Or Structural Change in the Global Oil Market?* Middle East Economic Survey. Vol XLVIII No 6 07-Feb 2005

the course of the past couple of years that most oil industry analysts began to accept the notion that we are in the midst of major and possibly lasting structural change in the oil market. "

"A definitive answer will probably not be known for a few more years, but … the current high oil price environment and oil price volatility are here to stay."

"Most oil industry analysts accepted the $18-20/B long term equilibrium price concept as internally consistent until the events of the past few years but especially in the wake of developments last year. "

"The prevailing view through to the middle of 2003 was that future modest oil demand growth would be fully covered by projected non-OPEC production This view of the market has so far proven to be wrong. Oil demand in 2003 rose at the highest level in half a decade (0.5mn b/d)."

"Oil market developments in 2004 could not have been more different than the mainstream perception in 2003. Actual oil consumption in 2004 turned out to be twice as high as the high end of the 2003 projections. At 2.6mn b/d, actual global oil demand grew at the highest level (in absolute terms) since 1975 largely due to strong global economic growth."

"Compounding the problems related to crude oil production capacity in 2004 was the tightness not only of global oil production but also of the entire oil supply chain, from exploration and production to transportation (tankers and pipelines) and refining. Years (perhaps decades) of underinvestment, largely due to low transportation and refining margins, have now come to haunt us. In particular, in the refining sector, it will take several years of good margins like in 2004 to encourage adequate upgrading investments to be made."

"Internal political and geopolitical developments interfered with the normal flow of oil production in 2004, in particular from Iraq where terrorist activities against internal transportation systems reduced oil export capacity and prevented capacity expansion. Also, terrorist threats in Saudi Arabia and strikes in Nigeria (which generally produces high quality crudes), helped push the oil price up in an already very tight physical market."

Cyclical or Structural Change

"Is the oil market undergoing major and lasting structural change reminiscent of developments in the 1970s and 80s, or do market developments in 2004 reflect the peak of a cyclical upswing, to be followed by a downswing sometime in the future? While the evidence is not yet conclusive, there are several indicators to suggest that the recent changes in the oil market are structural and that a return to the pre-2000 oil price environment is unlikely.

1. *The tightening of the entire oil supply chain In addition to upstream issues putting upward pressure on oil prices, there is the question of tightness in refining.*

2. *Access to oil reserves and resources it's more difficult to get access to technically attractive oil reserves (or oil exploration prospects) under acceptable terms.*
3. *The emergence of China and to a lesser extent India (together with other Asian oil consumers) has added a new dimension to the market.*
4. *A benchmark/hurdle rate price to test the economic viability of upstream projects most IOCs now use a price level closer to $25.*
5. *It has become clear that the $28/B high end of the OPEC price target is increasingly considered a new floor rather than a price ceiling for the OPEC basket. The Saudi leadership can no longer be seen to be unduly influenced by Western interests in determining its oil policy.*
6. *Internal political and geopolitical developments in the Middle East are increasingly influencing oil production and production expectations. Also in Africa and Latin America are in the midst of major socio-economic and political internal developments, which in some cases have led to oil supply disruptions."*

"A temporary return to much lower oil prices can still not be entirely excluded in the medium term but it would probably require either some or all of the following:

- *A deep global recession cutting into global oil consumption coinciding with either a determined OPEC policy to allow prices to fall in order to stimulate demand or, failure to adequately manage OPEC production.*
- *Stronger than expected non-OPEC oil production growth (in particular from the FSU) and/or OPEC capacity growth, coupled with weak demand growth and/or a failure (deliberate or accidental) by OPEC to manage the resulting cut in the demand for OPEC oil;*
- *An early return to peace and stability in Iraq coupled with a speedy recovery in the country's battered oil industry.*

"The arguments in favor of structural change in the oil market, resulting in a prolonged forward state of oil price volatility and continued high oil prices, appears to be overwhelming in comparison with the possibility that recent oil price developments only reflect the peak of an oil price cycle."

Current natural gas price estimates, such as those provided by the EIA in their Annual Energy Outlook 2005[16] are based on several assumptions:

- Operation of the Mackenzie Delta Pipeline by 2010
- Operation of the Alaska Pipeline

[16] Energy Information Administration. *Annual Energy Outlook 2005 With Projections to 2025* DOE/EIA-0383(2005) Feb 2005 www.eia.doe.gov.

- Growth in Rocky Mountain reserves
- New LNG facilities running by 2010.

All of these factors would require significant investment and removal or satisfaction of regulatory impediments and environmental approvals on an expedited basis. Even the most optimistic assessment includes a price increase after 2010 due to increasing exploration and extraction costs. Global demand for natural gas is expected to increase due to its status as a clean burning fuel that is preferred for electricity generation. As the economies of Asia and Latin America expand, demand for inexpensive electricity will continue to grow. It is estimated that by 2030, 27 per cent of all electricity generated world-wide will be from gas generation[17].

In addition to growth in demand, geopolitical factors can also affect the energy market. An article by Herman Franssen[18] summarized the key geopolitical factors that would affect oil prices, and reasons why previous oil price predictions had been inaccurate. Similar factors would affect the accuracy of estimates of natural gas prices. These factors are:

- Previous estimates ignored or underestimated depletion of existing resources
- Assumed low demand growth in 1990's would continue
- Assumed government policy and new technology would have improved efficiency
- Assumed high non-OPEC growth would continue
- Assumed supply and demand to be inelastic.

The article summarized reasons why it is unlikely that oil prices would drop to pre-2000 levels as follows:

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[17] ExxonMobil. *ExxonMobil's 2004 Energy Outlook.* http://exxonmobil.com/corporate/Citizenship/Corp_citizenship_energy_outlook.asp

[18] Herman Franssen. *The End of Cheap Oil: Cyclical Or Structural Change in the Global Oil Market?* Middle East Economic Survey. Vol XLVIII No 6 07-Feb 2005

- Supply chain is tight, as is refining: capacity in former Soviet Union may have peaked, depletion is occurring in non-OPEC nations and 1/3 of OPEC nations have already peaked.
- Under investment in infrastructure
- Political factors disrupting refining and extraction
- Much of the new reserves are technically difficult to extract, in remote areas or are politically undesirable
- Growth in Asia is rapid
- Saudi policy encourages high oil prices.

The conditions that must be met for prices to decrease substantially from their current levels on a sustained basis, even in the short and medium term are:

- A global recession
- Strong non-OPEC growth
- Rapid peace in Iraq.

The conclusions of this article suggest that these changes are structural rather than cyclical, and are therefore likely permanent. Given the intimate and growing relationship between gas and crude markets, these issues and assumptions would likely affect estimates of future natural gas prices. Numerous studies and reports draw parallels between the economics of the oil and gas industries[19,20]. However, blanket application of the principles of oil pricing to natural gas markets would be incorrect, because the natural gas market tends to exhibit more volatility due to weather and is more localized due to technical issues surrounding importing and exporting[21].

[19] RW Beck Inc. www.rwbeck.com
[20] RW Bentley. *Global oil & gas depletion: an overview.* Energy Policy 30(2002) 189-205
[21] Jerry Mahoney. *Experts Call Future of Natural Gas Prices a Guessing Game.* News Release, Feb 24 2004 McCombs School of Business. University of Texas at Austin
http://www.mccombs.utexas.edu/news/pressreleases/cefer04_wrap.asp

These localized infrastructure issues are the case in Ontario. Insight into the system operation, de-bottlenecking and infrastructure investment is necessary to allow the constraints that would prevent the natural gas market from properly functioning to avoid greater pressure on volatility and price level. Inaccurate price predictions could also be the result of over-generous estimates of domestic natural gas reserves, such as those estimates provided by the U.S. Geological Survey[22].

Various organizations suggest that the peak may occur at a somewhat different dates, based on their own assumptions and calculations. These suggestions are summarized in Table 5-2.

Table 5-2: Projections of Natural Gas Peak

Source of Projection	Projected Date
Backbiter	2006-2007
Simmons	2007-2009
Skrebowski	After 2007
Deffeyes	Before 2009
Goodstein	Before 2010
Campbell	Around 2010
World Energy Council	After 2010
Laherrere	2010-2020
EIA	2016
CERA	After 2020
Shell	After 2025
Lynch	No visible peak

Alan Greenspan, in testimony to the US House of Representatives Committee on Energy and Commerce[23] suggested that high natural gas prices are related to the lack of flexibility in the supply chain in the North American market, that is that almost all of the natural gas used in North America is produced here, making the market sensitive to increases in demand. He suggested that addition of LNG facilities, along with the

[22] Wikipedia. http://en.wikipedia.org/wiki/Peak_oil
[23] Testimony of Chairman Alan Greenspan *Natural gas supply and demand issues.* Before the Committee on Energy and Commerce, US House of Representatives June 10, 2003
http://www.federalreserve.gov/BoardDocs/testimony/2003/20030610/default.htm

implementation of improved technologies and expansion of imports was necessary to ensure supply adequacy.

Conclusion on gas prices pricing dynamics

The following conclusions regarding natural gas prices for new gas-fired generation in Ontario need to be considered in the supply mix assessment:

- The need to ensure adequate natural gas supply, storage and deliverability to and through Ontario to mitigate the risk on price level and volatility driven by unique power generation demands in a power and gas market that has not yet experienced nor been designed to operate with large daily volumetric and deliverability swings.
- The forecasted price level for natural gas has a significantly greater probability of moving to the high side than to the downside. Both crude and natural gas product pricing have or are in the process of establishing new floors as a consequence of internationalization of energy markets and dramatic upward increases in overall international demands for both fuels. There has been a structural change in the pricing of both products that leads to greater volatility and higher price levels.

5.2.2 MITIGATE RELIANCE ON NATURAL GAS

In considering electricity supply options, the impact on the fuel sources need to be considered. The Government's plan to replace coal-fuelled generation in Ontario results in increased reliance on natural gas generation, which impacts natural gas price, supply and usage. Increased natural gas fired generation results in upward pressure on natural gas prices, which in turn increases electricity prices. In addressing this concern the IESO in its July 8, 2005 10-year outlook[24] indicates that in developing a balanced generation portfolio there is the need for some new gas-fired generators to be dual fuel plants in order to minimize the fuel supply vulnerability of plants unable to maintain on-

[24] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

site fuel inventory. Increased reliance on natural gas as a generation supply resource therefore puts at risk adequacy, reliability and cost of supply.

While adding new gas generators to an existing fleet of generators to meet demand growth where risk and economic assessment indicates that it is reasonable to do so is sensible, replacing existing coal generation with new natural gas generation based on a political decision is not.

This summer's pricing is a reasonable example of what could happen if coal is phased-out and more gas is on the margin setting prices. With TransAlta, Brighton Beach on-line and 6 of 8 Nanticoke units off-line during peak conditions very high prices were experienced for both gas and electricity. The RPP plan calls for an annual average price of about $53. The current May 1, 2005 to August 3, 2005 average price is $71.44. It is likely that as a consequence there will be a large deficit in the RPP variance account, which will need to be cleared in May 2006 on top of the projected introduction of the May 2006 $58[25] RPP reference price.

The price of a supply resource directly impacts the price of electricity.

On July 27, 2005 Abitibi-Consolidated announced that it is closing its mill in Stephenville permanently and scaling down operations in Grand Falls-Windsor citing high energy costs, in addition to poor wood supply as the reason for the closures. The Stephenville mill, which employs about 280 people, will close in October 2005. Two machines at the Grand Falls mill, which employs 490 people, will be closed. Abitibi's case illustrates the impact that energy costs can have on industry, the economy and the people of Ontario.

There is no doubt that under the supply circumstances described by the IESO[26] that natural gas-fired generation of the size required to ensure supply adequacy with the phase-out of the remaining coal-fuelled generators (6,500 MW) will have significant impact on natural gas prices in Ontario, due to the size of the load as well as the unique load shape, which will peak both in the summer and winter. The winter peak on top of

[25] Navigant Consulting. Ontario Wholesale Electricity Market Price Forecast for the Period January 1, 2005 through December 31, 2006. Presented to Ontario Energy Board. March 7, 2005.
[26] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015

a very significant existing winter peak for current gas markets will create significant competition between historical and new loads for both capacity and volume. This will result in increases in Ontario's price levels and price volatility for both natural gas and electricity.

A high level comparison of current natural gas and coal price forecasts for electricity generators is presented in this section. An in-depth review of gas pricing dynamics was presented earlier in this submission in section 5.2.1.

According to the CGA[27]natural gas supply is increasingly obtained from higher-cost sources and that the trend for future average market prices is upward.

In mid-2004, the price of natural gas was at least $4.75 US/GJ[28] ($5.94 Cdn/Gj at an exchange rate of 1.25). BP Canada shows forecast natural gas prices at Henry Hub through 2010 ranging from $4.25 US/Gj to $7 US/Gj ($5.31 Cdn to $8.75 Cdn/Gj at an exchange rate of 1.25). With the demand supply scenario described earlier the price of natural gas can be expected to be volatile and with the replacement of coal generation with natural gas generation, this volatility will exacerbate electricity price volatility.

The mid-2004 price of coal at $0.35 US to $1.30 US/Gj ($0.44 Cdn/Gj to $1.63 Cdn/Gj) depending on the type of coal[29], is substantially lower than the mid-2004 price of natural gas at $4.75 US/Gj ($5.95 Cdn/Gj).

The Energy Information Administration (EIA) Electric Power Monthly[30]indicates that from July 2002 to September 2004 the average cost of fuel delivered to U.S. natural gas-fired generators was in the range of two to three times higher than the cost of coal per unit of energy. The EIA's 2004 outlook[31] forecasts annual increases in the natural gas price for electricity generation of 0.8 per cent per year for 2005-2025. The outlook for steam coal prices for U.S coal-fuelled generators is a decrease of 0.3 per cent per year, in real terms, for 2002-2025.

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[27] Canadian Gas Association. Understanding the North American Natural Gas Market. October 2003
[28] Thinking Energy. Ontario's Energy Crunch: Why Phasing Out Coal Is An Unwise Strategy. February, 2005.
[29] Ibid.
[30]http://www.eia.doe.gov/cneaf/electricity/epm/epm_sum.html
[31] EIA . Annual Energy Outlook 2004 with Projections to 2025. DOE/EIA-0383 (2004).

New Gas Services for New Gas Fired Generators

In its review of the DSS study's assessment of the impact of the large new gas-fired generation load, ERA noted the impact of a very unique and significantly different load profile on the Ontario gas and power market pricing. The new Clean Energy Supply RFP (CES) contracts entered into by the new generators have the natural gas price determined under the NGX Dawn daily index. A good portion of the supply used under the CES contracts will likely be purchased delivered to Dawn and when demand is high, prices will be higher not only for the generators, but also for existing Ontario gas users who are not on fixed price contracts, and over time all gas consumers will face higher gas prices.

The new gas-fired generators will be very large gas users and their loads will vary wildly through the day, month and season. Existing gas services and rates will not accommodate the load profiles of these new large generators and new services such as notice service, peaking service and multiple intra-day nominations will be required to provide the types of services required by these generators to operate effectively and economically in the market. These services still need to be designed and regulatory approval will need to be obtained. The Ontario Energy Board has just started a review of new gas services and facilities requirements for generators. It could take 2-3 years to design, obtain regulatory approval and implement the system changes required to be able to introduce these new services.

Dual Fuel Impacts and Price Volatility Impacts

Gas pricing based on a Dawn NGX index as proposed in the CES RFP, will likely increase gas volumes purchased and sold at the Dawn Hub 30 per cent. On current peak days, 50 to 100 MMCFD trades tend to move the market clearing prices. With the new gas-fired generators the number of peak day trades could increase to in-excess of 700 MMCFD resulting in capacity constraints that will have deleterious impacts on gas price. To illustrate the potential price impact of capacity constraints on the Ontario gas market, Union Gas, in 2005 evidence filed with the OEB describes a gas price spike at Parkway from $6.37 US/MMBTU to $65.00 US/MMBTU as indicative of the potential need for additional facilities.

ERA points out that the current nomination windows for gas and power are not aligned and that absent such an alignment, speculative trading and bidding could occur on peak days that will increase overall price volatility in both the gas and electricity markets in Ontario. Assuming the increased volume and volatility associated with this new large counter cycle load shape increases overall gas prices by 5 per cent to 10 per cent, Ontario gas consumers would be subject to an annual increase of between $0.70 billion and $1.4 billion per year.

Gas Import Export and LNG

To address current and anticipated demand levels, LNG terminals are proposed for eastern Canada. Increasing consumption significantly at a time when the international markets are moving to LNG will result in Canada exporting larger volumes of gas to the U.S. while importing more expensive LNG. Since the early 1990's Canadian gas exports have exceeded Canadian sales. Growth in export sales to the U.S. has been to gas-fired generators and in each of these markets where gas-fired generation was expanded, gas prices and price volatility increased. It is interesting to note that new gas-fired generation was not used to replace existing coal-fuelled generation in any of those U.S. jurisdictions.

5.3 NATURAL GAS ON-GOING SUPPLY ADEQUACY AND RELIABILITY

There is a substantial divergence between the supply adequacy and reliability that can be provided by natural gas and coal. The contrast, illustrated in this section speaks to the need to keep coal in Ontario's supply mix in order to mitigate reliance on natural gas as an electricity supply resource.

Natural Gas Supply

According to the Canadian Gas Association[32] two of three basins that supply the bulk of North America's natural gas were producing less total volume in 2001 than in the previous decades. The Gulf of Mexico supplied 11,400 BCF in 1980 compared to

[32] Canadian Gas Association. Understanding the North American Natural Gas Market. October 2003.

10,000 BCF in 2001, while the Mid-continental regions supplied 5,800 BCF in 1980 compared to 4,400 BCF in 2001. In the third basin, the Western Canadian Sedimentary Basin ("WCSB"), production capacity increased from 2,600 BCF in 1980 to 6,100 BCF in 2001 as a result of widespread drilling activity. However, the WCSB has now entered a phase of declining production as new wells are drilled (the "low hanging fruit" have all been picked). The CGA indicates that total volume "will need to be boosted via untapped conventional sources located in the Rockies and through improved drilling technology in and around basins in the WCSB, the Gulf coast, Arctic and Atlantic Canada regions to meet the growing demand for natural gas.

The CGA report indicates that based on a survey of industry experts, the annual average growth in natural gas demand is forecasted at 1.9 per cent per year from 2002 to 2020 with the North America demand barrier expected to break 30 TCF by 2009 (mid-term). On the supply side, the CGA reports divergent views with forecasted growth ranging from a minimum of –0.1 per cent to a maximum of 2.3 per cent over the 2002 to 2020 period. Experts agree, however, that acceleration in supply responsiveness is needed to meet the mid-term 30 TCF demand. The CGA adds, "Expected rigidities in the supply side response generally lead to higher price outlooks for natural gas".

The CGA identifies issues that need to be addressed to improve supply response as including: timely permitting and granting of land access, and the allocation of benefits to Aboriginals; facilitation of timely pipeline and storage construction by lowering investor's risk through higher rate of returns and government and regulatory certainty; and, more efficient and cost effective environmental policies.

Given the North American natural gas market scenario drawn by the CGA for the period 2002-2020, the PWU submits that there is reasonable indication that reliance on natural gas as an electricity generation supply resource will compromise Ontario's future electricity supply adequacy and reliability.

Coal Supply

In contrast to natural gas, North America's coal reserve is plentiful and, according to the World Energy Council as cited in a 2005 Thinking Energy publication[33], proven reserves are estimated to provide 200 years of supply. Canada's coal reserve is estimated to be sufficient for 97 years. This abundant supply enables OPG's coal-fuelled generation to provide for future electricity supply adequacy and reliability.

Ontario's coal generators have a demonstrated track record of providing supply adequacy and reliability. In its July 8, 2005 10-Year Outlook[34], the Independent Market Operator (the "IESO") states:

> *"Coal supply makes up a large part of Ontario's flexible generation, and it has traditionally been required to meet changing demand, to supply demand when other supply sources are unreliable, and to balance load and generation at all times."*

Given this pronouncement on coal generation, it would be counterintuitive to preclude coal from Ontario's long-term supply mix. Rather, coal generation needs to remain in the supply mix to ensure Ontario's future supply adequacy and reliability. This means keeping existing coal generators retrofitted for clean coal technology in-service as well as adding new clean coal-fuelled generators to meet load growth where supported by economics and risk analysis.

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[33] Thinking Energy. Ontario's Energy Crunch: Why Phasing Out Coal Is An Unwise Strategy. February, 2005.

[34] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

6 IMPLEMENTING THE SUPPLY POLICY FRAMEWORK

In this section, we demonstrate how the clean coal case fits the PWU's proposed supply policy framework. This will ensure the continued economic prosperity and social welfare of the people of Ontario by providing a reliable, adequate, safe and reasonably priced future supply.

As noted in section 3, a supply policy framework must ensure:

- Continued operation of existing generation for the remainder of their economic lives;
- A diverse mix of supply resources; and,
- Proper planning, rigorous analysis, and public consultation regarding any major changes to the manner in which Ontario's energy needs are met, including full compliance with the *Environmental Assessment Act*.

6.1 CONTINUED OPERATION OF EXISTING GENERATION

The benefits of continued operation of existing coal stations retrofitted with clean coal technology are discussed here and examples of how other jurisdictions are investing in clean coal technology are provided. Further, the IESO's concerns regarding system risks associated with coal closure are also described. As well, details on gas infrastructure requirements related to replacing coal generation with gas generation are described and comments on the cost benefit of coal closure are provided.

6.1.1 RETROFIT OF COAL GENERATION WITH CLEAN COAL GENERATION

Ontario has already made substantial investments in coal-fuelled generators and site network infrastructure, and refurbishment and adaptation for continued use of these assets must be considered as an alternative to wasteful abandonment. The clean coal case sees the continued operation of all existing generating stations including Ontario's

coal-fuelled stations retrofitted with clean coal technology. As illustrated in section 4, this will result in lower generation costs compared to the coal closure case. It also avoids the incremental gas infrastructure and variable costs related to replacement gas-fired generation. In addition, higher reserve margins with clean coal enhance system reliability by decreasing Ontario's reliance on other jurisdictions for electricity.

OPG's coal-fuelled generation is a key contributor to Ontario's peak electricity supply adequacy and reliability. All coal-fuelled plants should be retrofitted with clean coal technology and should continue to operate, ensuring the sustained value of Ontario's investment in coal-fuelled plants. Doing so maximizes the benefits reaped from generating assets that have substantial remaining useful life as well as real book value.

The clean coal case also includes the rehabilitation of Pickering NGS Units 2 and 3, which contributes to lower generation costs than with coal closure, and helps to avoid incremental gas infrastructure and variable costs. Upgrading and rehabilitation will contribute to higher supply adequacy and reliability that will be reflected in higher reserve margins under the clean coal scenario

Nuclear generation is the technology that provides the largest share of Ontario's baseload supply and the Government is wisely investing in the refurbishment of some of the decommissioned nuclear units.

Existing generation, including all coal-fuelled generators retrofitted with clean coal technology, must continue to operate in order to:

- Accomplish the Government's environmental objectives sooner;
- Mitigate reliance on natural gas;
- Ensure on-going energy supply adequacy and reliability in the short- and long-term; and
- Ensure the most reasonable energy price.

Cleaner Coal Technology

In this section we address the retrofit of coal-fuelled generation and how this will enhance environmental performance and efficiency and contribute to the economic and social welfare of the people of Ontario.

The following statistics puts the contribution of Ontario's coal-fuelled generators' emissions to Ontario's air pollution into context. Data compiled by the Ministry of the Environment in 2001 referenced by OPG[35], indicates that about 50 per cent of Ontario's smog, as represented by SO_2 and NO_x emission rates, comes from U.S. sources. Of the 50 per cent that originates in Ontario about 6 per cent comes from coal-fuelled generation, while 32 per cent comes from transportation, and 11 per cent from other sources. Since the 2001 data compilation, Lakeview GS has been taken out of operation, and NO_x emission control technology has been installed on two units at Lambton GS and two units at Nanticoke. The proportion of Ontario's smog originating from Ontario's coal-fuelled generation, therefore, can be assumed to be lower today than the levels reported in 2001.

Effectiveness of FGD and SCR

For both SO_2 and NO_x proven emissions mitigation technology exists today. Flue gas desulfurization (FGD) scrubbers reduce the levels of SO_2 and selective catalytic reduction (SCR) units reduce the levels of NO_x. The effectiveness of these technologies in reducing SO_2 and NO_x emissions are considerable as illustrated by a comparison of the 2003 SO_2 and NO_x emission rates for Lambton GS Units 1, 2, 3 and 4 presented in Table 6-1. Lambton GS Units 3 and 4 have been retrofitted with FGD and SCR, while Units 1 and 2 have not. The 2003 average SO_2 emission rate for Units 3 and 4 at 0.8 kg/MWh is approximately 88 per cent lower than the average SO_2 emission rate for Units 1 and 2. The 2003 average NO_x emission rate for Units 3 and 4 at 0.35 kg/MWh is 68 per cent lower than the average NO_x emission rate for Units 1 and 2. The SCR units for Lambton's Units 3 and 4 came into service in August 2003. Thus Units 3 and 4's

[35] Ontario Power Generation. August 14, 2003 News Release. Ontario Power Generation's Lambton Station Completes Installation of Newest Smog-related Emission Reduction Technology.

lower 2003 NO_x emission levels compared to those for Units 1 and 2, presented in Table 6-1 reflect the impact of less than half a year of SCR operation. Table 6-1 also shows that in 2002, prior to the installation of SCR, the NO_x emission rates for Units 3 and 4 were within the range of the NO_x emission rates for Units 1 and 2.

Table 6-1

Lambton Generating Station
Units 1/2 - LNB
Units 3/4 - LNB, SCR, FGD

- **Emissions 2003, reported by Ontario Mandatory Air Emissions Monitoring & Reporting**

	SO2 (kg)	SO2 (kg/MWh)	NOX (kg)	NOX (kg/MWh)	MWh
Unit 1	18,795,000	7.3	3,204,000	1.2	2,578,775
Unit 2	16,366,000	6.0	2,608,000	1.0	2,722,000
Unit 3	2,107,000	0.8	1,060,000	0.4	2,575,000
Unit 4	2,813,000	0.8	1,007,000	0.3	3,351,000

- **Emissions 2002, From Annex A Facility Info. Report (CEA Mercury Program)**

	SO2 (kg)	SO2 (kg/MWh)	NOX (kg)	NOX (kg/MWh)	MWh
Unit 1	12,950,000	5.6	2,207,000	1.0	2,319,000
Unit 2	11,900,000	5.5	1,777,000	0.8	2,150,000
Unit 3	2,790,000	0.8	3,339,000	1.0	3,414,000
Unit 4	2,242,000	0.9	2,671,000	1.0	2,572,000

Capital Cost of FGD and SCR

A comparison of capital costs for emission control retrofits and for new natural gas combined cycle generation, extracted from the Thinking Energy's February 2005 publication[36], is presented in Table 6-2. The table indicates the substantially higher capital cost of building new gas generation compared to retrofitting coal-fuelled generators with emission control technology.

[36] Thinking Energy. Ontario's Energy Crunch: Why Phasing Out Coal Is An Unwise Strategy. February, 2005.

Table 6.2 Comparison of Capital Cost of Emission Control Technology and Gas Generation	
Option	**Cost $US/kW**
Low NO_x Burners plus SCR	175
Wet Scrubber	150
Wet ESP	40
Dry Scrubber	140
New Combined Cycle Natural Gas Generation	700-1,000

Source: Thinking Energy, Feb. 2005.

Clean Coal in Other Jurisdictions

Other jurisdictions including the U.S. and Europe recognize the advantages of having coal-fuelled generation in their supply mix and are investing in the development of cleaner and more efficient coal technology while reducing electricity costs. Several examples of successful projects incorporating cleaner combustion and production technologies and organizations leading the development of clean coal technology are described here.

Japan

In Japan, J-Power, the former Electrical Power Development Corporation of Japan that was privatized in October 2004, built the Tachibana-wan Power Station, Japan's largest coal station consisting of two 1050 MW supercritical pulverized coal units. Unit two came into service in late 2000. Tachibana-wan Power Station is one of the most efficient pulverized coal stations in the world and was identified by the European Commission Power-Clean R, D&D Thematic Network as the best reference plant

amongst "state-of-the-art" pulverized coal technology. Prior to the 1970's Japan relied extensively on large oil-fired boiler plants[37]. As a result of oil price shocks in the 1970's, Japan initiated a total review of domestic electricity economics, which triggered a need for fuel diversification and energy savings. This resulted in the increase of nuclear baseload and imported coal as fuel options in the 1980's to lessen the reliance on oil.

United States

In the U.S., the Department of Energy (DOE) Clean Coal Technology Demonstration Program is providing support for 35 first-of-a-kind projects underway or completed in 17 states[38]. It includes high-tech concepts expected to pioneer the next generation of super-clean, high-efficiency power plants such as:

- Advanced combustion technology (Integrated Gasification Combined Cycle, Fluidized-Bed Combustion).
- Environmental control technologies including desulphurization, NO_x reduction, combined SO_2 and NO_x reduction, mercury reduction, etc.
- Energy policies and goals articulated through federal government (i.e. DOE, Environmental Protection Agency) and state governments and agencies (i.e. California Energy Commission, State of California).
- An example of a successful greenfield project supported by DOE is the Tampa Electric Integrated Gasification Combined-Cycle Project. It is a 315 MW (250 MW net) IGCC plant in Polk County, Florida. The plant uses low-cost higher sulphur coal, petcoke, petcoke/coal blends and biomass as fuel. The project demonstrated that the plant removed 97 per cent of the feedstock sulphur, NO_x emissions were less than the 50 per cent of New Source Performance Standards for electric generator units, volatile organic compound emissions were negligible, and mercury emissions without controls were half the potential release based on mercury levels in the coal. After only a year and a half, the unit availability to deliver power to customers was 90 per cent. The project, which continues to

[37] www.meti.go.jp/english/policy/index_metipolicies.html
[38] http://www.netl.doe.gov/cctc/

operate commercially, has been the recipient of numerous environmental and technological achievement awards including: Ecological Society of America Corporate Award, Florida Audubon Society Corporate Award, Power Magazine Plant of the Year award.

European Union

In Europe, the European Commission (EC) initiated CARNOT[39] and PowerClean[40]. The CARNOT program objective, with funding of 3 million euros, is to promote the environmentally sound use of solid fuels through the use of clean and efficient technologies and industrial strategic cooperation.

PowerClean is a research network group under the EC which, among other things:

- Promotes collaboration, co-operation, and exchange between EC supported research projects and researchers.
- Helps maintain the technical and industrial content of future European energy-related research and to contribute to identifying future research priorities for clean power generation.
- Supports innovation in the European power generation and equipment manufacturing sector.

The general perception is that the European Union lags their major industrial competitors, the U.S. and Japan, which both have long-term visions that include coal and advanced CCTs as a major part of the overall technology mix for a sustainable future. However, they have centrally coordinated research networks with stated policies and objectives and a database of advanced technology case studies. In a recent PowerClean report[41] the following outlook was given:

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[39] European Commission. *Fostering the use of clean coal technologies -the CARNOT Programme*. Luxembourg: Office for Official Publications of the European Communities 2001- 32 pp. ISBN 92-828-8874-6.

[40] Fossil Fuel Power Generation Within The European Research Area. Report prepared by PowerClean R, D&D Thematic Network, 10 December 2003.

[41] Fossil Fuel Power Generation Within The European Research Area, Report prepared by PowerClean R, D&D Thematic Network, 10 December 2003.

> *"The prevailing view is that the future energy needs of the enlarged EU will be so significant that the full range of available fuels (including renewables, nuclear, natural gas and coal) will have to be utilised on an environmentally acceptable basis to meet the demands. For example, some 550GW power plant (90% of present capacity), will have to be built between now and 2030 if new demand and essential replacement due to age are to be satisfied. All the recent major economic projections suggest that coal must remain a key fuel source for power generation, and hence that new power plants must include advanced Clean Coal Technologies (CCTs).*
>
> *On a global scale, coal demand is expected to double over the period to 2030, and the IEA estimates that 4500 GW of new power plant will be required. Coal is expected to provide 40% of this, with an investment value of €1450 billion. This is a massive export market for which European industry must compete against the USA, Japan, and domestic suppliers within the target markets. The development of CCTs with higher efficiencies and better environmental performance, are seen as key enabling steps in this competition, and for the medium to long-term creation of near-zero-emission power."*

A key observation and conclusion is that coal "has a very strong strategic role to play in the context of security of supply because of the amount available, its wide distribution, ease and low cost of transport, and its history of price stability. Its use would reduce EU dependence on a single source and a single fuel."

Therefore, even if centralized and coordinated policy is not as far advanced towards CCT for the EU as it is in the U.S. or Japan, the difficult questions and issues are being considered. Even this is an advance over the current supply policy for Ontario.

World Energy Council

The World Energy Council (WEC) is an 81-year-old organization that provides information and research on all types of energy, including coal, oil, natural gas, nuclear, hydro, and renewables, and is UN-accredited, non-governmental, non-commercial and non-aligned. WEC is a UK-registered charity headquartered in London. The WEC's view as presented in one of its publications[42] is that coal is part of the solution of sustainable development and energy poverty eradication and that coal will be increasingly clean.

[42] http://www.worldenergy.org/wec-geis/global/downloads/pubs/coal_summ.pdf

International Energy Agency

The International Energy Agency (IEA) provides support for over 40 international co-operation and collaboration agreements in energy technology R&D, deployment and information dissemination. The key objectives of the IEA Implementation Agreement on Clean Coal Science are to promote research on coal, from the science of coal combustion, conversion and utilization to co-firing and bio-co-processing. To this end the participating nations in the Implementing Agreement for a Program of Research, Development and Demonstration on Clean Coal Sciences have developed a variety of means to share and develop coal combustion technology. Participating countries are: Australia, Canada, Denmark, Finland, Germany, Italy, Japan, Mexico, the Netherlands, South Africa, Sweden, United Kingdom, and the U.S.. The Chairman is from Canada (NRCan).

6.1.2 RISKS RELATED TO CLOSURE OF COAL-FUELLED GENERATION

Phasing-out coal-fuelled generation results in the abandonment and waste of quality generating assets that have a substantial useful remaining life, as well as real book value. Replacing coal-fuelled generation with gas-fired generation compromises the future supply adequacy, reliability, safety and reasonableness of price.

In its July 8, 2005 IESO 10-Year Outlook[43], the IESO notes that the phasing-out of the remaining coal-fuelled generators from 2007 to 2009 is the largest and most significant change in the history of Ontario's electricity system and involves major technical considerations with significant risks and challenges that need to be addressed. Further the IESO notes that historical patterns of congestion are expected to change significantly due to coal replacement. Coal-fuelled plants provide load pick-up and drop out capability that may be reduced if the coal-fuelled plants shut down. Once a target shutdown has been established for each plant, the risk that it will be 'harvested' and become less reliable and possibly inoperable increases as the shut down date

[43] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

approaches. The IESO also notes that significant operating issues that affect the reliability of new generation units is typical for a period following their in-service date. The IESO therefore identifies the need to have the coal generators available for a period to maintain reliability if necessary, as a critical requirement of the government's coal phase-out plan.

In addition to the impact on supply mix, the IESO notes that half of the 26 transmission projects identified in its July 8, 2005 10-year outlook are related to coal-generation shutdown: 6 related to Nanticoke GS shutdown; 6 related to Lambton GS shutdown; and, 1 to Atikokan GS shutdown. These projects represent major challenges and expenditures.

Reactive power is needed to maintain adequate voltage throughout the system, and Nanticoke GS is particularly important because it supplies a major portion of the reactive power required to transport power to south-central Ontario and the western GTA. Nanticoke GS reactive power also supports transmission of its own energy to the GTA as well as that produced by Bruce GS and in southwest Ontario. The shutdown of Nanticoke GS will mean:

- The output of Bruce GS will be significantly restricted, jeopardizing the return to service of Bruce units 1 and 2;
- The flow east to the GTA will be substantially restricted;
- The operation of more expensive generation will be required; and,
- Imports from Michigan will be restricted, increasing prices and degrading adequacy of supply;
- Replacement supply will need to be located near the load.

The IESO points out that the root cause of the August 14, 2003 blackout was a severe shortage of reactive power in northern Ohio caused by power plant and transmission failure. This emphasizes the significance of maintaining adequate reactive power.

The IESO report indicates that there are serious issues that all Ontarians should be concerned about with respect to the current plan to replace coal-fuelled generation.

The following are some of the main concerns extracted from the IESO report that illustrate the concerns that knowledgeable energy personnel have identified:

- Even with the measures outlined in the IESO report it is unlikely the need for dynamic voltage support from Nanticoke will be eliminated. It may be necessary to convert several units to synchronous condenser operation (at least 2 units).
- Because of the high level of uncertainty and the severity of the consequences of supply shortages it is critically important that the coal replacement plan incorporate rigorous risk mitigation measures and controls.
- During summer periods, peak demands typically occur during hot periods with little wind, the type of weather, which pushes air conditioning loads to their maximum. The reduced contribution from wind during these periods increases the power system's reliance on alternative supplies of capacity.
- Coal-fuelled generation currently provides an important capability to meet load pick-up and drop out requirements. That capability may be reduced when the coal plants shutdown. Conservation, while reducing overall requirements, will not likely change the load pick-up requirement. Much of the renewable generation is expected to be wind power which cannot effectively be ramped up or down to meet changes in demand
- Historically in Ontario, very short time balancing "automatic generation control" has been provided by a small number of hydroelectric plants. Restrictions on the allowable limits within which hydroelectric facilities operate would require extending the use of automatic generation control to more market participant generators.
- Ontario's future generation supply mix will place an increasing reliability value on the flexibility of generating assets to provide load following capability, operating reserve and automatic generation control.
- Connecting large amounts of wind to the grid will not be without challenges. Early studies indicate wind should make significant contributions to energy but there is less certainty with respect to the peak meeting capacity contribution that wind will

make. For the purposes of its study, the IESO assumed 10 per cent of the installed capacity of wind-powered generation can be relied on at the time of the annual peak.

- An HVDC interconnection with Hydro Quebec of 1,250 MW transfer capability would improve interchanges between Ontario and Quebec. At this time**,** this project has high project uncertainty.

6.2 DIVERSE MIX OF SUPPLY RESOURCES

The PWU believes that Ontario must continue to have a diverse supply mix to ensure and enhance supply adequacy, reliability and reasonableness of cost. As such the PWU supports the following supply mix recommendation of the government's Conservation Action Team report that:

> *"The Government of Ontario recognize an appropriate supply mix consisting of a balance of the following which builds on the strength of our existing electricity generation system and its highly skilled work force:*
>
> - *A viable nuclear component that utilizes installed and new capacity;*
> - *A hydro-electric component that includes both large and small scale facilities;*
> - *A fossil fuel component provided it is "clean", and;*
> - *A renewable component that would include but not be restricted to wind generation and biomass."*

However, the PWU disagrees with the definition provided for a "clean" fossil component. The PWU firmly believes that Ontario does not have to wait for major breakthroughs in coal gasification technology to take advantage of North America's abundant, affordable, accessible and secure supply of coal.

In the following sections we describe issues related to resource supply price, adequacy and reliability that speak to the need to keep clean coal in Ontario's future supply mix.

6.2.1 CLEAN COAL IN ONTARIO'S FUTURE SUPPLY MIX

The issues related to gas infrastructure, price and supply presented in section 5 speaks to the need to keep coal generation in Ontario's future supply mix. The Government's supply plan for Ontario abandons cleaner coal technology without proper research or, as noted earlier, without a realistic cost benefit analysis. With the continued use of coal-fuelled generation in the U.S., Ontario electricity imports from the U.S. will come in part from coal-fuelled generation that contribute significantly to smog in Ontario, given that the source of more than half of Ontario's smog causing pollutants is the U.S. In a March 5, 2005 paper, Dr. David McKeown, Medical Officer of Health, Toronto Public Health on curbing transboundary air pollution[44] notes that a significant number of sources of the pollutants are coal-fuelled generators. The paper also points out that, on average, Lakeview GS, Lambton GS and Nanticoke GS generate lower emission levels relative to US plants upwind of Toronto. Data sourced from the 2004 Commission for Environmental Cooperation of North America in Dr. McKeown's paper shows that overall SO_2, NO_x and mercury emission levels from Lambton GS and Nanticoke GS are lower on a per MWh generated basis than emissions from any of the US plants upwind of Toronto. NO_x emissions from Lakeview were also lower while its SO_2 and mercury emissions were comparable to the U.S. generators with emissions in the lower range. Should an overly aggressive timeline for coal replacement result in a supply shortfall that increases Ontario's dependence on U.S. imports, the result would be higher pollution levels in Ontario not lower levels of pollution.

Ontario needs to recognize that clean coal should be an important component of the province's future supply mix and in turn invest in making coal-fuelled generation as environmentally sustainable as possible.

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[44] Dr. David McKeown, Toronto Public Health. Curbing Transboundary Air Pollution: Protecting Health Through Legal Action. March 2005.

6.2.2 REALISTIC EXPECTATIONS OF RENEWABLE ENERGY SOURCES

The government has placed particular emphasis on expanding renewable generation in the province as a way of creating new capacity. However, the OPA needs to ensure that the assessment of renewable energy supply is realistic in particular with regard to wind power. As noted earlier, the IESO assumes that only 10 per cent of the installed capacity of wind-powered generation could be relied on for the annual peak demand. In addition, costs related to implementing technical solutions to reliability issues need to be included in assessing large wind farm projects as part of Ontario's future supply mix. A March 15, 2005 report released by the German Energy Agency, Deutsche Energie-Agentur GmbH in Germany[45], suggested that there are significant transmission reliability issues associated with the integration of large wind farm projects to the grid.

6.2.3 CONSERVATION AND EFFICIENCY

Conservation and efficiency targets included in a supply plan must be based on rigorous analysis and realistic expectations, and unsupported conservation and efficiency forecasts should not be given undue merit. Unrealistic expectations will jeopardize future supply adequacy. As an illustration, while the Government has set a target for energy conservation to reduce peak consumption by 5 per cent by 2007, the IESO in its July 8, 2005 10-year outlook[46] has not reflected these targets in its Ontario demand forecast. The IESO states that its reason for doing so is that "the impact of new conservation initiatives is as yet difficult to forecast".

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[45] Deutsche Energie-Agentur. Summary of the Essential Results of the Study. Planning of the Grid Integration of Wind Energy in Germany Onshore and Offshore up to the Year 2020 (dena Grid study). By the Project Steering Group. March 15, 2005.

[46] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

6.2.4 HIGHLY SKILLED ENERGY WORKFORCE

The Government's Conservation Action Team correctly identifies the strengths of the existing electricity generation system and its highly skilled workforce as the basis required on which to build the future supply mix.

The experience and expertise of OPG's workforce was evidenced during this July's heat wave when strong performance from OPG's generating stations helped meet the province's record high demand of more than 26,000 MW. With the exception of hydroelectric generation, Ontario does not have extensive experience with renewable generation, nor with large natural gas-fired generation. As referenced earlier the IESO has indicated that significant operating issues affecting the reliability of new generation is typical for a period following the in-service date. With the installation of generation types with which there is limited experience and skills in the province, the operating issues can be expected to be even greater than where the workforce has substantial experience and skills.

In considering a resource plan for Ontario, the value of existing workforce experience and skills should be taken into account as well as the direct and indirect impact of the resource plan on jobs, and the related impact on the economic and social welfare of Ontarians.

6.3 PROPER PLANNING AND COMPLIANCE WITH ENVIRONMENTAL ASSESSMENT ACT

OPA supply policy should ensure proper system planning and a full and comprehensive environmental assessment of the province's energy needs, all available resource options and alternative methods of implementing each option preceding individual decisions to add generation facilities and any final decision on the plan as required under the *Environmental Assessment Plan Act*. This means that clean coal-fuelled generation is an option that the OPA must include. It also means that a proper system plan must include a full and comprehensive environmental assessment of the

Government's coal replacement plan before any individual decisions are made to add new generation facilities. Apart from the legal requirements, moving forward with a procurement process in the absence of such an assessment, is likely to result in haphazard and ill-conceived decisions that puts at risk Ontario's adequacy and reliability of supply.

Should the Government proceed with its coal-fuelled generation closure plan following a full review of supply mix options by the OPA, it will do so with full awareness of the impact of coal generation phase-out and with full public disclosure of the impact of its decision, not only on the environment, but also on the economic and social welfare of the people of Ontario.

7 CONSIDERATION FOR CDM PROGRAMS

Global Energy's comments to the PWU on CDM programs, notes that Ontario's electricity system load factor at 0.7-0.8 is high relative to the average of other North American jurisdictions, which range between 0.5-0.6. The scope for load shifting in Ontario, therefore, is more limited that in other jurisdictions.

In addition to the issue of ensuring that CDM program costs are justified based on avoided costs and program specific costs Global identifies the following four additional issues that are important in designing CDM programs:

- Environmental effects;
- Impact on electricity rates;
- Customer class equity considerations; and,
- Local distribution utility costs.

8 ASSESSING ENVIRONMENTAL IMPACTS

Global Energy's comments to the PWU on assessing environmental impacts, point out that there are a large number of factors that need to be considered in conducting an environmental impact assessment. The following are of specific note:

- Effect on emissions, locally, nationally, and on the international level;
- Differences in the amount and type of solid waste resulting from each case;
- Differences in fuel sources and their relative impact;
- Impact on wildlife.

Some factors are difficult to measure in monetary terms. In particular, Global notes that the impact on wildlife is hard to conclusively compare because the value and relative importance of effects is largely subjective.

9 CONCLUSION

Available evidence demonstrates that a transition to clean coal generation will be less expensive than the replacement of coal-fuelled generation with gas-fired generation even under conservative gas price and demand growth assumptions. Furthermore, the gas supply and price forecast uncertainty is a significant risk in replacing coal-fuelled generation with gas-fired generation. There are significant gas infrastructure costs that have generally been left out of the coal closure analysis (e.g. the DSS study) that add substantially to the cost of coal closure. Coal closure will have an impact on both electricity and gas prices. The OPA should recognize the total impact on energy costs in looking at the implications of shutting down coal-fuelled generation rather than moving to clean coal-fuelled generation. Coal closure presents significant risk to the system that will be difficult to manage effectively. Failure to consider clean coal as an option will impact the economy and social welfare of the people of Ontario.

Coal closure will make Ontario more dependent on other jurisdictions for electricity compared to the clean coal option. Ontario has been a net importer of electricity in all but one year since 1998. To address Ontario's supply shortage all existing generation should be kept operational, decreasing the dependency on imports.

The IESO expresses numerous concerns related to the impact of coal closure on system reliability. Of particular note are the IESO's comments related to the load growth forecast. To maintain system reliability it will be critical to ensure that there is no slippage in the in-service dates of the new generation. Based on the forecast load growth, ERA points out that putting in place incremental gas infrastructure according to the Government's coal replacement timeline will be a challenge, which suggests the slippage in the in-service dates of this new generation is likely.

Evidence included in this document shows that clean coal supply better meets the objective of an adequate, reliable, safe and reasonable priced supply compared to the coal closure. Coal closure results in: substantially higher generation costs; additional incremental natural gas fixed and variable costs; substantially increased transmission

costs related to the major and complex coal closure transmission projects identified by the IESO[47]; and increased gas prices and volatility for gas consumers.

The latter two outcomes add significant cost impact to the coal closure case that both electricity and gas consumers will be paying for over the next 20 years.

The higher generation costs and incremental gas costs related to coal closure can be expected to be reflected in the Provincial Benefit charge that was introduced on electricity bills earlier this year as well as in gas bill amounts. Clearly, these costs must be quantified and considered in the assessment of all options to ensure the best supply plan for Ontario. Anything less would be negligent.

With regard to emission reductions, there is a need to consider whether the substantially higher cost of coal closure compared to clean coal to achieve 20 per cent more emissions reductions above the 80 per cent that clean coal can accomplish is truly justifiable. Such an assessment would show whether the proposed expenditures for new generation could be better directed to other priorities, such as, cleaner generation technologies, energy efficiency, education, etc. This is of particular importance since Ontario is becoming increasingly dependent upon imports of electricity from other jurisdictions. Ironically, coal closure will likely result in higher levels of pollutants in Ontario since the closures are likely to result in increased imports which will be supplied by increased operations of coal-fuelled stations in neighbouring U.S. states have higher emission rates than Ontario coal-fuelled facilities.

The PWU energy plan enhances supply adequacy, reliability and reasonableness of price and maximizes the value of the existing system in which Ontarians have already made significant investments. Existing coal generation retrofitted for clean coal generation with extended life service for all units beyond 2025, and new clean coal generation where supported by cost benefit analysis must be considered as an option for Ontario's future supply mix.

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[47] IESO REP 0245v1.0. 10-Year Outlook: And Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2006 to December 2015.

The OPA needs to be prudent and have a plan that is not exposed to higher and more volatile natural gas costs, does not place undue reliance on alternate supply options that can provide reliable capacity and is responsive to a high demand growth scenario. The Province should recognize the potentially deleterious economic impact and risk associated with coal closure. Such an assessment will lead them to the same conclusion we have reached. It is time to step back from their determination to execute a supply plan, which has not been properly and publicly vetted. Ontario consumers, industry, commercial businesses and residential users deserve a more balanced energy strategy. Doing so will result in a cleaner environment sooner at substantially lower costs and risks.

Attachment 1

List of PWU Employers

Atomic Energy of Canada Limited (Chalk River Laboratories)
Barrie Hydro
BPC District Energy Investments Limited Partnership
Brant County Power Incorporated
Brascan Power Corporation - Lake Superior Power Inc.
Brighton Beach Power Limited
Bruce Power Inc.
Corporation of the City of Dryden - Dryden Municipal Telephone
Corporation of the County of Brant
Electrical Safety Authority
Erie Thames Services Corporation
Goldman Hotels Inc. - Hockley Highlands Inn & Conference Centre
Great Lakes Power Limited
Grimsby Power Incorporated
Halton Hills Hydro Inc.
Hydro One Inc.
Independent Electricity System Operator
Inergi LP
Innisfil Hydro Distribution Systems Limited
Kenora Hydro Electric Corporation Ltd.
Kincardine Cable TV Ltd.
Kinectrics Inc.
Kitchener-Wilmot Hydro Inc.
London Hydro Incorporated
Middlesex Power Distribution Corporation
Milton Hydro Distribution Inc.
Mississagi Power Trust

New Horizon System Solutions

Newmarket Hydro Ltd.

Norfolk Power Distribution Inc.

Ontario Power Generation Inc.

Orangeville Hydro Limited

PUC Services Inc.

Sioux Lookout Hydro Inc.

Sodexho Canada Ltd.

TransAlta Energy Corporation - O.H.S.C. Ottawa

Vertex Customer Management (Canada) Limited

Whitby Hydro Energy Services Corporation

PROVINCIAL COUNCIL OF WOMEN OF ONTARIO est. 1923

August 22, 2005

Ontario Power Authority
supplymixsubmissions@powerauthority.on.ca

Re: Ontario's Future Electricity Mix

As President of the Provincial Council of Women of Ontario (PCWO) whose membership encompasses many thousands of Ontario citizens, through its 18 affiliated member groups, I am pleased to submit our views on what Ontario's future electricity mix should be.

PCWO has long standing energy policies regarding the dangers of nuclear power and the need for energy conservation, renewable energy and energy efficiencies, upon which we have based many presentations to the Government, and its Boards, Agencies and Committees ex: the Select Committee on Alternative Fuel Sources (02).

As well, from 1992 to 1995 PCWO participated in a National Council of Women of Canada (NCWC 1893) Energy Conservation Program, which involved a Canada-wide survey of citizen energy use, research, a quarterly conservation newsletter and public programs hosted across the country by Local Councils of Women, for example: an open house in Fort St. John featured off-grid solar technology etc.

Upon completion of the project NCWC recommended that the Federal Government conduct a

national campaign to:

- show cost/benefit ratio for alternatives to consumers
- make an energy connection, showing the less obvious costs ex: transporting water to the tap"
- publicize available technologies
- give information and incentives to owners and builders
- encourage research and development and public/industry/government partnerships ex: the Green Community program

It is ten years since we made these recommendations and three years since we presented our brief regarding Alternative Fuel Sources. Much has happened in the energy field, despite a tendency of successive governments at both federal and provincial levels to hang back on making investments in these areas, and in some cases actually cut funding for worthwhile energy efficiency and conservation projects such as the Green Communities Program.

Therefore, PCWO is most pleased that the Province has set up a Conservation Bureau and that OPA is working with its lead person Mr. Love, to enhance energy conservation initiatives. **PCWO believes that energy conservation should be the key long-term ingredient of your 20year electricity plan for Ontario.**

In our 2002 Brief (mentioned above), we noted that:

"a 1988 study by Ralph Torrie and David Brooks estimated that primary energy usage could be reduced by 50% by the year 2025 and in 1993 Natural Resources Canada research concluded that Canada's energy efficiency potential is 30% by the year 2000. Recent studies by the Pembina Institute show that "electricity and peak demand could be reduced to 30% below 2004 levels by 2020 through a series of energy efficiency and demand reduction policies."

In contrast with our view on energy conservation and efficiencies, Council of Women has long standing policy regarding the need to phase out nuclear power as an energy source in Ontario at the end of each plant's life span, and we are pleased by the Province's recent announcement that the Pickering A- 2 and 3 units will be phased out immediately.

The use of nuclear power presents many problems, such as significant dangers in all its phases, huge costs of new nuclear plants, nuclear plant inefficiencies, cost over-runs and break-downs, as noted by the Minister of Energy, Dwight Duncan in a recent speech to the Empire Club, and the failure of the federal government to find a solution to the disposal of used nuclear reactor fuel - a solution that will at best be many more years in coming.

In light of this, we submit that **nuclear power should be a quickly dwindling part of the electricity supply mix,** and question the advisability of huge investments in nuclear as predicted in an August 2nd Globe and Mail e- article by OPA **and most recently more definitively by the Minister of Energy'** in an August 20th article in the Toronto Star.

In summary, PCWO urges the OPA to:

- **encourage the Government of Ontario to engage the public in its energy-future plans, preferably in a broad-based government consultation, before committing to new nuclear power as a substantive part of the energy mix**

- **in its 20 year plan, maximize energy conservation and renewable energy sources, which could, according to the Pembina Institute, offer as much as 60% of our energy needs**

- **increase its recent tentative use of innovative measures such as standard offer contracts**

- **enhance demand reduction measures ex: follow the lead of other jurisdictions such as California in offering rebates to those who conserve significant amounts of energy**

- **involve as many energy conservation and renewable technology experts as possible, in order to have the most up-to-date information in this very important energy-planning endeavour**

- **as a shorter term measure, in between the shut down of coal-fired generators and assuring long term supply from renewable and energy conservation, contract natural gas supply and support co-generation projects**

- **employ full-life-cycle cost accounting for any options chosen, which should include the broader social, health and environmental costs etc.**

- quickly reduce the nuclear component of the energy supply in line with a phase out of nuclear plants at the end of their life cycle.

PCWO would be pleased to be part of any further discussions on this matter and we attach our 2002 brief to the Select Committee on Alternative Energy Sources. We are encouraged that some of our recommendations in this Brief have been acted upon, such as the 'time-of-use' metering, and a commitment to an enhanced role for the Adam Beck Station in Niagara Falls, but know that much more must be done to ensure a green and sustainable electricity future for Ontario.

Sincerely,

Milica Kovacevich, President

Cc: Gracia Janes, PCWO VP Environment

Attachments

Presentation to:

THE SELECT COMMITTEE ON ALTERNATIVE FUEL SOURCES

Prepared by:

THE PROVINCIAL COUNCIL OF WOMEN OF ONTARIO

Queens Park, February 20th 2002

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Council of Women History: International, National, Provincial and Local :

Since the inception of the International Council of Women (ICW) in 1888, Councils of Women world-wide have made environmental protection a high priority. For instance, as early as 1905-10 Montreal and Toronto Councils of Women lobbied successfully for water filtration, and in 1978, the National Council of Women of Canada (NCWC) was one of the first groups to raise concerns around acid rain. For many years, ICW has had Consultative Status 1 with the Economic and Social Council of the United Nations (ECOSOC.); and permanent and accredited representation to such UN agencies as the Food and Agricultural Organization and the Environment Program. In 1997, NCWC gained Consultative Status 11 with ECOSOC and brings its environmental concerns to UN special sessions, such as that of March 3-17th this year. For its part, the Provincial Council of Women of Ontario (PCWO) has each year since 1923, presented its environmental concerns to the Government of Ontario in a Semi-Annual Brief, and on a continuous basis, through letters and briefs to the Government and its Boards, Committees and Agencies.

Councils of Women, representing millions of citizens in 70 countries around the world, offer expertise, opinion and involvement, based upon democratically developed policies, across a broad spectrum of issues, in order to make this world a better place. It is in this spirit that PCWO presents the following comments.

Introduction/Overview:

The Provincial Council of Women of Ontario (PCWO) commends the Select Committee for this long overdue review of alternative energy sources. We see this as an ideal opportunity to develop an ambitious and visionary energy strategy for Ontario. **If such a plan were to be completed over the next 30 years, in this the most populous province in Canada - and the industrial engine of the country, Ontario would lead the way for other jurisdictions, and help ensure an environmentally secure future for all Canadians.**

The Committee has rightly recognized that the issues of alternative energy sources and energy conservation touch upon a host of inter-related areas of public concern, such as pollution, global warming, urban sprawl, public health and other social, environmental and economic issues, of importance to Ontario citizens.

It is because of just such concerns, that PCWO has supported important environmental measures e.x: **the phase out of nuclear power, the use of alternative sources of energy and energy conservation, a stop to urban sprawl, preservation of prime farmland, strict regulations to curb the degradation of land, air and water, and initiatives to preserve and enhance our natural resources for future generations.**

PCWO is concerned that **such a significant proportion of Ontario's energy needs are met through the use of non-renewable and environmentally destructive energy sources.** Oil particularly is subject to the whims of the world-wide supply and demand, and both oil and coal will eventually run out. In the meantime their use contributes heavily to global warming, acid rain and other pollution problems. Even gas, is non-renewable and emits some green house gases.

As well, **Ontario is far too reliant on nuclear energy**, which is extraordinarily costly, has worrisome health, safety and environmental risks attached to its extraction, use and after-use wastes; does not significantly alter our capability to lower green house gas emissions; and, has become a sought after business opportunity, for plant renewal and expansion in any privatized energy market. If unchecked, we **could soon see the renewal of aging nuclear plants, beyond a safe life span, construction of new plants, and growth, rather than a curtailment, of nuclear energy use and waste in Ontario and the USA.**

All of Ontario's traditional sources of energy have been heavily subsidized for many years, through tax concessions, rebates, direct grants and low interest loans. For instance, energy economist David Argue and nuclear researcher David Martin, estimate there were $15.2 billion (1997$s) in subsidies to the nuclear industry up to 1997[1]

In contrast, renewable energy sources and energy conservation, which have the potential to protect the environment, lower health costs, reduce global warming, advance technological markets and job creation, reduce acid rain, and conserve scarce resources, have been neglected for too long.

Only in a time of perceived crisis, ex. the 70s oil shortages and to-day's threat of global warming, do governments move more quickly to develop ecologically friendly energy sources and promote energy conservation., rather than waste.
In fact, evidence at the 1989 Federal Standing Committee on Environment

Hearing regarding global warming showed that after the 70s oil crisis had settled down Federal funding of energy efficiency and alternative energy technologies fell from a high per year of $550 million in 1984 to $50 million in 1989, and a "consequential" number of businesses failed as a result.[2]

Given the dramatic downside to the past and any future reliance on traditional energy sources and the considerable ecological, health and economic benefits of renewable energy sources and energy conservation, **Council of Women asks that this Committee give renewable energy and energy conservation the green light they need to move onto a level playing field, and then into the vanguard of Ontario energy policy and practice**. **Only then may we grab this opportunity to improve our natural, physical and social environments and make a very necessary investment in the sustainability of our communities, our province, country and planet**

Council of Women Policy/Action on Renewable Energy Sources, Energy Conservation, Nuclear & Related Issues:

We make these latter recommendations, and those that follow, based on long standing policies of the Provincial Council of Women of Ontario and National Council of Women of Canada. For instance, in 1978, PCWO asked the Government of Ontario to –

"in lieu of further nuclear development, shift its investment priorities to energy conservation and the development of renewable energy sources."

In 1989, a National Council of Women Brief to the Federal Standing Committee on Environment re global warming, noted that-

"energy efficiency and conservation are essential in the reduction of CO2 and other greenhouse gases, and have other beneficial social side effects, such as :

- ***stretched fuel supplies (which are not inexhaustible)***
- ***decreased automobile pollution, which will lessen side effects to health from low level ozone***
- ***reduced need to expand the less economically efficient and potentially dangerous forms of energy such as nuclear***
- ***reduced fossil fuel emissions, especially from coal, which will in turn reduce acid rain and improve air quality***
- ***reduced home and industry heating and operating costs."***

- ***increased jobs***
- ***lower dependence on foreign fuels***
- ***limitless supply of alternative sources eg. solar, use of a variety of energy sources which lessens the threat of failure of supply."***

In evidence given to the Federal Standing Committee, international environmental consultant Jeff Passmore, stated that the barriers to energy conservation and alternative energy use were not technical, attitudinal or financial, but purely political.-

"For instance, Solar fuel goes head to head with diesel fuel in remote communities in northern Canada. Diesel fuel is tax exempt for the generation of electricity and solar is not. Automatically photovoltaics is 13.5 % more expensive. *3*

About nuclear power's role in the reduction of CO2 Mr. Passmore said-

*" **A lot of people suggest that nuclear power is a solution. I would argue that it can offer too little too late. As a contributor to a reduction in carbon dioxide emissions, nuclear energy is a non- starter. To offset 5% of 1990 global carbon emissions , world nuclear capacity would have to double**."*[4]

Regarding the use of nuclear power and the need to move towards less dangerous and more sustainable forms of energy, PCWO has made presentations to the Standing Committee on Resource Development Re: Bill 118- An Act to Amend the Power Corporation Act (92), the Select Committee on Ontario Hydro Nuclear Affairs (97), the Standing Committee on Resource Development re Bill 35 (98), the Federal Nuclear Fuel Waste Management & Disposal Concept Environmental Assessment Panel, Phase 11 and 111 Hearings (96/97); the Government of Canada Public Consultation on Options for Federal Oversight - of nuclear waste disposal(98); and the National Energy Board consultations on Canadian Energy Supply and Demand to 2025 (98).

At this latter consultation, Provincial Council of Women stressed **the need for involvement in the Federal planning of experts such as Mr. Passmore, rather than just those of the traditional non-renewable sector.**

As well, PCWO has sent numerous letters to the Government warning of the dangers of privatization of Ontario Hydro, and in 1998 asked that it-

" retain Ontario Hydro as a Crown Corporation, ensure that nuclear plants are phased out, ensure sustainable energy strategies and alternative energy sources be key features of a long term energy plan."

As part of a two and a half year NCWC Energy Conservation Project, funded by Environment Canada, Partners Fund from 1992-1995, Council members from across Canada were surveyed on their energy use and habits; local public forums were held; and a quarterly newsletter The Conserver was published; Results of the survey (excerpts encl.) showed that-

" ***Canadians are trying to save energy, and that the government should conduct a broad based awareness campaign to help educate Canadians regarding energy conservation measures and alternative energy sources, and to internalize the need to save energy , as they did in the 2nd World War and the 1970' s energy crisis."***

It is against this lengthy background of interest and involvement in renewable energy and energy conservation, that Council makes its remarks on the Select Committee's Interim Report. We do not purport to be experts in either the technology or the costs/benefits of a forward-looking energy strategy for Ontario. Nevertheless, Council has followed this issue closely for many years and represents a very broad spectrum of the public. **Our observations may well provide some insights into how the public views the important issues that are being explored, their support for any chosen plan, and ways they could be part of the solutions**.

This brief cites established policy, and research by groups and individuals ex: Dr. John Bacher, author of Petrotyranny, and researcher/co-author of Get A Life (1st edition) and researcher for the NCWC Conservation Project (brief encl.) and for the Preservation of Agricultural Lands Society, Niagara Conservation Strategy

The Broad Policy Objectives for a Future Policy Framework:

PCWO agrees wholeheartedly with the general broad policy objectives for the "Policy Framework". Nevertheless, the fact that OPG, the dominant player/generator of power in Ontario, considers -

"green-power as part of wider mix of generation, including traditional sources of large hydraulic, nuclear and fossil generation sources",

makes it very clear to us that there will be a continued nuclear dominance of the energy field. PCWO sees any long-term continuation, or expanded role of nuclear energy, to run directly counter to the Commission's objective to -

" support the development of alternative fuels and energy use in Ontario".

Therefore, we cannot state too strongly, the need for provincial policy to support reductions in the Ontario's substantive 40- 60 % reliance on nuclear energy, starting with a shut down of nuclear plants as they reach the end of their projected life spans. Such a shut down was promised by Ontario Hydro in evidence entered at the Federal Nuclear Waste Management Hearings, [5] and in 1998, Ontario Hydro staff indicated to the Federal Energy Supply/Demand 2025 consultations that **there was no Provincial policy supporting new nuclear plants for the future.** [6]

We are concerned that there appears to be a move Provincially, without public discussion, to maintain the existing over- reliance on nuclear power, and to enhance and expand its use. A May 2001 article in the Globe and Mail noted -

" The biggest sign of Canada's nuclear revival is the restart, expected next year of Pickering A nuclear station. The plant, Canada's oldest, began operating 30 years ago and was shut down in 1997" (due to safety concerns) [7]

As well, British Energy (BE) is now in charge of the Bruce nuclear plants, and has expressed some interest in the Pickering plants. UK reports show that safety at privatized nuclear plants is a real concern ex: a September 1999 report from the British Nuclear Installations Inspectorate (NIL) indicated that British Energy has cut costs by reducing maintenance expenditures, laying off large numbers of employees and contracting out. In addition they are supporting significant life extensions of older plants. The NIL has suggested that British energy has at times lost managerial control of nuclear plants by contracting out, and there is also concern that in some areas, safety has been sacrificed due to the emphasis on output.[8] Most recently, the Toronto Star reported that AECL has already signed partner agreements with BE to develop the "Next Generation" nuclear technology in order to "attract potential buyers in Europe and the US.." [9]

In the United States, the Yucca Mountain disposal site may soon be approved, and after a 30 year period in which no new nuclear plants have been built, due to serious concerns regarding potential accidents, terrorist threats and waste disposal problems, American business interests are

applying to prolong the life of older nuclear plants and build more. The Earth Island Journal reports that-

"***In a little-noted correction, published in the July 30th (US)Federal Registry, the Nuclear Regulatory Commission (NRC) confirmed that re-licencing aging US reactors for another 20 years would release 14,800 person-rems of radiation per plant. The NRC calculated that this exposure would cause 12 deaths per reactor. With as many as 100 reactors seeking operating extensions, this would mean 1,200 cancer deaths***."[10]

In Canada, Federal Policy requires nuclear generators to be responsible for their waste, and we are many years away from what will be an enormously costly solution to this extremely troubling problem. After 7 years of study, the Federal Review Panel on the Management of Nuclear Wastes turned down the government's application to bury the waste in the Precambrian Shield in 1998, in large part due to public's "***grave unease***" [11].This issue will be reviewed over the next several years as an oversight committee grapples with the problem.

We would note also, that nuclear is a very expensive energy source, and it was this undue expense that led to an **extraordinarily onerous debt for Ontario citizens**.

PCWO believes the enormous investment in nuclear power has been a significant factor in the lack of investment in alternative forms of renewable energy, and Ontario Hydro has promoted nuclear power as a cheap form of energy and encouraged its inordinate and wasteful use.

We note that a February 18th Globe & Mail article drew attention to the fact that many American States do not consider nuclear power to be at all "green", and some will not be allowing the importation of power from this source.[12]

Promoting the Supply of 'Green ' Renewable Energy (page 13)

Commentary:

PCWO is disturbed that, in its "Commentary" the Select Committee states that -

" ***An important part of the context for any such development is Ontario's upcoming open electricity and natural gas markets***."

This statement, and others within the text, link the 'opening of the market' with the acceptance and support of alternative energy sources. **They give the appearance that this Committee is part of a government justification of the 'opening of the market and the privatization of Ontario's publically-owned generating and transmission assets**

The very important goal of promoting the supply of green renewable energy does not, and should not rely on an 'open market'. This goal should be attained **through a 'publically -owned' system . We would also note, that a "private system" is not necessarily one that will promote the interests of the public, or be one which fosters more 'green' energy**. In fact, according to the research of author Dr. John Bacher -

" ***There is little evidence that deregulation anywhere, has been part of successful strategies to provide more green energy, despite new provisions for consumer choice to purchase green power. To the contrary, there are examples of successful public utility programs and policies. Areas of California which were exempted from the deregulation process, notably Los Angeles, made the greatest progress in achieving stimulating green power, under the leadership of its public utility.***" "**T*here are many other examples of green public utilities both in Europe and the United States. Such good environmental records have not been shared by the large private corporations which are currently lobbying for privatization and deregulation."***[13]

Given that the "primary purpose of developing alternative energy is to protect the
environment", and knowing that environmental degradation has accelerated in tandem with human activity and use of the earth's resources ; and that the promotion and use of alternative resources already lags far behind the more destructive non renewable and nuclear energy sources, **Council of Women would urge the Commission to set a renewable energy target at least as high as that of the European Commission i.e. to meet a 12 % target from renewable sources, based on clean technologies such as solar, wind and fuel cells, by the year 2010.**

We note that mega- dams and nuclear power are both in decline in most of Europe, and that according to the Royal Society of Canada's Canadian Options for Greenhouse Gas Emissions panel, **every dollar invested in renewable energy displaces seven times as much CO2 emissions as the same dollar invested in nuclear power**.[14]

Public Policy Questions (page 4) - Promoting the Supply of Renewable Energy:

1. **Provincial Strategies- immediate and long-term priorities**

PCWO sees no way to promote renewable energy development successfully in the absence of a **Provincial strategy**. **Such a strategy must be linked to our support of the Kyoto target and must be developed right away. Experts in the renewable energy should be consulted.**

While initially, one might plan for the furthest advanced , widely used and most cost competitive technologies to take the lead, ex: hydrogen fuel cells, wind power, and co-generation, **the enormous health -related costs of polluting energy sources such as coal and oil, should place the development of all renewables, and energy conservation , high on the agenda. Each will fill a niche, and combined they could well replace our heavy reliance on fossil fuels and nuclear power, sooner rather than later, with less threat of interrupted supply.**

2&3. Financial Incentives/Policies/Market Barriers etc.

Council feels that non-renewable sources of energy have had the benefit of many years of tax breaks and financial incentives, to the detriment of alternatives. **It is vital that renewable, clean green sources of energy be supported as needed**. One way to move renewable sources along, could be the development of photovoltaic cells. Dr. Bacher notes that-

"***what is required, is to bring down the cost of photovoltaic generation to that of coal. The simplest way is to achieve mass production of thin photovoltaic cells. This would be achieved*** **by the construction of a plant producing annually 100 megawatts of power-about ten times the** ***production capacity of any existing facilities***." [15]

He further notes, that respected British geologist Jeremy Legget has estimated the cost to be $100 million, far less that what might be spent on provincial highways over the next several years. **16**

There is a need to broadly popularize new technologies . There have been many excellent suggestions from previous witnesses ex: renewable energy targets, net metering and enhanced energy efficiency standards. The Government should also
offer low interest government loans to consumers, perhaps through **a reactivated**
Green Communities program, so that they may more quickly achieve retrofits and purchase energy saving devices

We consider that the "total level of assistance" to be given, should be whatever is needed. This is too crucial a situation to be put on the back burner. The savings in the long term and the various benefits we have previously outlined ex: jobs, reduced health costs, etc. will more than make up for any short term investments that might be considered at any point in time to take too much of the Provincial budget.

Council notes that, in the UK, a "Climate Change Levy" (CCL) is in effect. Large energy users have been required to pay an amount equal to 15% of their energy bills into a government fund. Small business and renewable energy purchasers are exempt from the CCL, while major energy users can offset the cost of the levy if they reduce their energy bills by 20%. Companies that meet energy -savings targets will receive an 80% discount on the CCL. While funds from the CCL go towards the country's social security fund, such a levy here could well be used to enhance alternatives and energy conservation.**17**

The Province should also :

***back up its very energy conscious "smart growth" planning policies, with strong land preservation policies and a concentrated effort to reduce expenditures on highways - the engine of urban sprawl and general environmental degradation through car emissions**

- **develop regulations to limit sulphur levels in gas, to at least those of other provinces.**

- **use government buildings and services to 'pilot' and popularize alternatives**

- **place strict emission caps on energy generators**

4&5 Green Power Procurement Policies& Renewable Portfolio Standard

If a green power procurement strategy is to be successful, it must be one that is set by Ontario and apply to energy suppliers, in or out- of- Province. The key would seem to be the procurement of the needed "green " energy to meet certain targets, regardless of the source of supply. This might result in a speeding up of Ontario-generated green energy, should for instance, Ontario Generation Co wish to compete with green energy produced in Manitoba.

PCWO fully supports the need for a renewable portfolio standard. As our 1999 Policy states, Council supports mandatory quotas for renewable energy from generators and retailers as prerequisites for any meaningful move towards energy and wide-spread move to alternative energy forms. Again, we note that many American states are setting renewable portfolio standards, and "green" may be defined in different ways .

6. General Targets Within a Portfolio

The adoption of various targets for specific "green"sources, would give some incentive to their production, particularly those that are more difficult to bring on stream, at any point in time

7. Monitoring Mechanism

Council of Women Policy supports either an independent monitoring agency, the Ministry of Environment, or amendments to Bill 35 , to enable the OEB.

8. Full life Cycle Costing

PCWO agrees that it would be a good idea **to do a full life cycle accounting for alternative and non-renewable energy sources, in order to know the**

"true" costs of both ,and more realistically consider the savings achieved through the use of renewables and the need to move quickly in this direction. Such knowledge would also help to overcome political barriers. Full life -cycle accounting should include such externalities as:

- **health costs from incidents of low level ozone (hospital entries and length of stay, lung disease, increase of asthma in children near highways** [18]
- **costs of revamping and reactivation of nuclear plants, decommissioning of nuclear wastes (present and future)**
- **energy efficiencies**
- **the savings that could be achieved through use of renewables**
- **employment potential**
- **projected market share and income for new Ontario technologies**
- **costs of waste**

With regard to this latter point, we note that a Toronto Star article of August 26/02 reported that-

" A U.S. study has predicted that by 2005, Americans will waste almost 7 billion hours a year sitting in stopped up traffic. The cost to the country, in lost time , gasoline consumption, and wear and tear on cars , will be $115 billion a year." [19]

As well, a January 12/02 Globe article drew attention to the significant environmental and health damages of "Light Pollution" , which is often wasted energy. [20]

9,10 Provincial Procurement Targets/Lead Agency

For any alternative energy strategy to be effective, the government, should take a leadership role through policy and action. As PCWO stated early on in 1977, " ***the government should expedite and enhance long term programs to encourage the use of renewable energy sources***."

The Provincial government, through its ministries, agencies and boards, should determine ambitious procurement targets and programs. In other jurisdictions such far-sighted leadership is well advanced. For

instance, the Los Angeles Department of Water and power (LAPWD) has a program to get the price of solar energy down to $2.50 per watt and to launch LA as a solar power city, which is ***"attracting PV manufacturers to locate there***", and Seattle City Light is mandated by its city council to obtain 100% of its new energy needs from renewables, land fill gas and energy conservation. The city has also adopted an aggressive energy conservation program and has **invited bids to develop renewable energy sources from independent power producers**. [21]

Closer to home, Toronto has made the reduction of greenhouse gases a priority. It has reduced its emissions by 67 %, and has exceeded by more than three times its 1990 goal for a 20% reduction by 1998. [22] The significant side effect, is that while reducing methane emissions at its garbage dumps, Toronto has used these gasses (collected) to provide power.

PCWO considers the many issues involved in moving quickly forward towards optimum energy conservation and use of alternative energy sources, as well as
cleaning up the environment etc., to involve all ministries. It is these same ministries that will have to work together and do this quickly.

Therefore we would see an inter-ministerial group as the best instrument for change.

11, 12 Alternative fuel/energy research and development programs, relevant to Ontario's economy & joint financing

Given Ontario's economic reliance on a healthy automobile sector, a research and development program could well tap into the potential of such technologies as the hydrogen fuel cell technology. For instance, Ontario could encourage transportation authorities to convert bus fleets, and could invest in the technology developed by Niagara Falls native Geoffrey Ballard and co-funded by Ballard Systems and the Federal government. Research in this area could be furthered if Ontario renewed its sponsorship of the Institute of Hydrogen Studies. And, Ontario could well assist in the creation and operation of a significant fuel cell demonstration project.[23]

13,14 , Emissions Trading and Credits Policy

PCWO has no policy on this, but notes that recent US studies show a substantive decline in CO2 emissions where such trading takes place [24]

15,16,17,18,19, Green Power' Initiatives of Ontario Power Generation

PCWO supports the location of wind turbines wherever they are feasible. If the stations are privatized, there should be requirements for wind power to be utilized on the appropriate sites.

20,21, Role of the Ontario Energy Board

PCWO took a keen interest in Bill 35 and the roles and responsibilities of the Ontario energy Board and requested the government to amend the Act to , amongst other things-

" enhance the promotion of energy conservation and renewable energy".

This is an important goal of both the Energy Efficiency Act and the OEB Act, and it is of **great concern to Council of Women that with the proposed market opening, two time honoured costs saving measures - time use of rates and load management- will no longer be allowed**. Municipalities have been employing time of use rates and load management for years to defer capital construction costs and keep electricity prices down for their consumers. It appears that load management will not be permitted as the market will be based on offering one price- the spot market price. Time-of-use rates, which allow large customers to save money during peak periods by buying less power then, (and offsetting these purchases by load shedding or alternative electricity production ex: natural gas) will also not be allowed, as such rates are contrary to the Board's Electricity Rate Handbook. [25]

Council sees these prohibitions as leading to the demise of these time - honoured cost saving measures - and to energy efficiency and demand side management (DSM) as a whole. They run directly counter to the promotion of energy conservation and renewable energy use.

22,23, Relationship to Other Levels of Government

Given the huge role Ontario and its many municipalities play in the economy of Canada and in environmental stewardship, all levels of

government should work together to reduce our energy consumption and move to renewable energy sources. In some cases, such as the new provincial pledge to reinvest in municipal transportation systems - which will help curb the use of automobiles, the federal governments recent promise of incentives for wind and small hydro [26], or Toronto's curbing of greenhouse gases, only one level of government is currently involved. **PCWO sees it as essential that there be a multiplier effect through joint investments.**

24-31 Energy Conservation and Efficiency and Education and Consumer Awareness.

Most experts in the energy field agree, that **Canadians are energy gluttons**, being the second highest per capita consumers of energy in the world [27], and that the potential for efficiency measures in Canada is enormous. A 1988 study by Ralph Torrie and David Brooks estimated that **primary energy usage could be reduced by 50% by the year 2025, and 1993 Natural Resources Canada research concluded that Canada's energy efficiency potential is 30% by the year 2000.** [28] Of course, this latter target has not been reached, **and the longer we wait before making substantive investments in this area, the less apt we are to meet the 1988 estimates, or to achieve the economic, health, social, environmental benefits of reducing our use of non renewable and/or environmentally unsustainable energy sources**.

We draw the committee's attention to Jeff Passmore's testimony to the Federal Standing Committee on the Environment re global warming that-

*" **The nice thing about efficiency is that it is irreversible.. regardless of what happens to energy prices, after it is done, very rarely is it undone. Once people have implemented an energy efficiency measure, they typically leave it there. If it is new process technology, if it is new lighting fixtures or whatever, they are not going to try to take it out if suddenly energy prices fall."*** [29]

With respect to public involvement and education, Council of Women recommend the same measures as those given to the Federal Government from the NCWC Energy Conservation Project in 1995, to encourage the involvement of consumers in a more directed way .i.e.

- ***show the cost/benefit ratio for alternatives, so that people could know for instance, if a solar hot water heater were purchased, how long will it take to recover the cost through savings in fuel or hydro bills***

- ***make the 'energy connection' so that people will know the "less obvious costs ex: costs of transporting and treating water";***

- ***publicize the available technologies-"people need to know where to get them and have choices."***

- ***give information and incentives for owners and builders to" encourage the use of energy efficient materials and appliances , in retrofits and new building construction."***

- ***encourage research and development in this area and public/industry/government partnerships, such as Ontario's Green Communities Program, to help make homes more energy efficient , at a cost savings to owners and renters.***

- ***invest in " improved transit systems, use of car pools, bike trails and measures to discourage car use."***

We note, that in the energy crisis of the 70s, both levels of government initiated awareness campaigns. For instance schools in Ontario fostered programs that had students checking room temperatures and turning down the heat when unneeded. And, energy conservation booklets with many 'tips' were widely distributed.

Council also recommends that, any energy strategy should include a consumer "survey" such as that done by the National Council of Women. While the general results would probably be similar, there would be 'niche' areas where public use and acceptance of a technology, might signal the need to quickly move in this direction, perhaps with incentives ex:. in the Green Communities Program municipalities, certain uptake levels for solar water heaters etc. may show up . **A comparative survey of 'green" and "non-green" communities could be very informative.**

We note that in the Green Communities program, it was found that for every "home energy audit" that was done, an average of between $1,200 and $1,800 was spent on energy saving improvements and technologies eg. solar water heaters. This was generally investment straight into the community businesses and trades.

Specific Alternative Energy Sources and Technologies

As we are not experts in this area, PCWO will comment only generally on some of the specific energy sources, give some examples of their application and refer to specific PCWO policies ex:. the need to use the most up to date technology in converting coal stations to gas.

31,32,33,34,35, Water Power

It would appear that the larger the project, the greater the impact on Ontario's environment; whereas smaller projects, with due attention to mitigation measures, may well help in areas on, or beyond, the existing grid. **Council has strong national policy opposing Quebec's Grand Beleine hydro project**, because of environmental concerns, as well as **policy asking the government to protect Canada's bio-diversity.** On the other hand, we would **favour smaller projects such as the Adam Beck Three station,** which seems to provide an opportunity to gain additional electricity capacity in an environmentally sensitive way, having received approval under the Environmental Assessment Act in 1998, after a detailed review and long community consultations.

36,37,38, Wind Power

PCWO draws your attention to a UK plan to spend $2.4 billion on 18 offshore wind farms of the coast of England and Wales, expected to produce enough electricity to power 1 million households by 2005, which will be a tremendous boost for jobs in the energy and engineering sector. [30] In Canada, Natural Resources Canada noted that in 1994, supply costs for wind power were between 5.3 to 10 cents/kilowatt hours which makes wind power " competitive with residential electricity and oil and commercial electricity."[31] While critics often cite the problems of 'intermittency" of wind power, the Worldwatch Institute believes that "large amounts of wind power can be integrated into power systems without in any way threatening

reliability."[32] **The wind station at the Pickering Plant, should be repeated wherever feasible, whether on privately owned or public sites.**

39,40,41,42, 43, Solar Energy

Council research for the NCWC Energy Conservation project, found that solar has tremendous potential as alternative energy source, particularly passive solar, and our Canadian technology has been adapted world-wide. Given that water heating accounts for up to one quarter of the average residential energy consumption, it is not surprising that, in 1998, Canada had 12,000 residential solar water heaters installed and Natural Resources Canada (NRC)estimated that 90,000 solar hot water systems would be installed in Ontario alone, over the next 20 years. According to NRC, recent technological advancements in the use of photovoltaics, has significantly reduced the cost of PV electrical energy and made it cost competitive with all forms of electricity generation. [33]

One example of the use of photovoltaics, is at Carleton University, where a PV lighting system was installed in 1994. The systems are self contained, provide reliable area lighting to any location, and are ideally suited for off-grid locations where power is unavailable or uneconomical. [34]

As for the usefulness of solar technology in a northern climate , according to energy expert Jeff. Passmore, -

"you merely tilt your connector to face the sun at an equivalent to the latitude you find yourself in. So in Canada, in southern Ontario, you are looking at tilting it at 45% towards the south. What you accomplish in doing that, is that Toronto has 80% the solar gain of Miami." [35]

In this regard, NCWC's Energy Conservation survey found that in Fort St. John BC, people were using photovoltaic composting toilets, passive and active solar houses, solar food driers and solar powered communication systems.

The Provincial government should definitely, take advantage of solar's potential for energy savings, job development, reduction of environmental pollutants, as a part of any kind of system- deregulated or not. As a potential income generator and a symbol of the Government's intent to lead the way, Dr. Bacher suggests that -

" One way would be for Ontario to become the world-leader in super-windows, which would actually heat buildings. Existing window prototypes of this technology would be mass produced , assisted by guaranteed purchase by the provincial government and the MUSH sector." [36]

44,45, 46, 47, Fuel for Fossil Generating Stations

In its most recent Brief to the Government, PCWO indicated its concern that the planned conversion of the Lakeview Generating station to gas, would -

"Allow the generator to emit almost twice as much CO2 and five times as much Nox as high efficiency, combined cycle natural gas turbines."

Nevertheless, since gas is a non-renewable energy source, and even with efficiencies there are greenhouse emissions, Council feels that this should be an interim measure, and that **the long term goal should be the phase out of coal fired stations**.

Council is also concerned that, with any opening of the electricity market, the impacts of trade agreements may well mean it will be impossible to control the emissions from the USA, or any private generator in Canada.

52,53,54,55,56 Fuel Cells and Hydrogen

We note, that the key component of Iceland 's ambitious goal to have **no fossil fuel consumption by 2030**, is the development of hydrogen fuel cells, for use in such projects as the conversion of buses to fuel cell use and then cars, in the Capitol city of Reykjavik. In Ontario, only Windsor has ambitious plans to green its buses through use of the fuel cell technology developed by Ballard Industries. [37] **Given Ontario's reliance on the automotive industry for jobs and economic prosperity, it would make sense to plan for far more projects of this sort within a very short time frame.** Council agrees with many of the excellent recommendations of witnesses to date ex: demonstration projects, fuel cell systems in government buildings, and bus fleets. This is a technology where the main impediment to its application is political will. If a small country like Iceland can manage to move quickly forward, so can Ontario.

57,58,59 Biomass Fuel Energy

As early as 1982, National Council of Women of Canada, supported increased financial assistance, research and development of Biogas from farm wastes .A Provincially developed prototype Biogas /power production could allow for the benefits described by NCWC as -

"diversification of Canada's energy sources, elimination of numerous environmental problems; development of opportunities for business and employment."

Council also noted that -

" ***systems already devised and in use in Canada, the US and other countries have been shown to be economically feasible, environmentally sound, and adaptable to all climates, and recent improvements in design and techniques have resulted in an increased yield in Biogas."***

In 1996, NCWC asked Federal Government to encourage the use of ethanol blended fuel by **extending the federal excise tax exemption to ethanol blends of gasoline, noting that this was a "secure" source of fuel.**

60-65 Other Fuel/Energy Sources and Applications

PCWO has no policy regarding most of the applications mentioned eg. peat extraction , but given our strongly expressed opposition to nuclear power over many years, we are definitely opposed to any government support and investment in the Thermonuclear Experimental Reactor. Far too much investment has already been drained away from alternative energy sources, and far too much risk and cost is involved in pursuing nuclear technology.

Co-Generation

Council believes that natural gas is a bridging mechanism, and has good potential in co-generation energy use. Savings from co-generation are not limited to the industrial sector, but many municipalities, universities, and hospitals are using co-generation for heat, light, air conditioning etc. For instance at Carleton University an $8.5 million co-generation project uses natural gas for heat and electricity. [38] Natural gas is however a non-

renewable energy source, and therefore efforts should be made to develop other sources ex: methane from dumps and animal compost.

Conclusion

Provincial Council of Women of Ontario believes that to achieve an economic and environmentally sustainable future for Ontario and Canada, governments at all levels must focus sustained research, development, investments and supportive policies and programs in alternative forms of energy and energy conservation.

Our current patterns of energy use are not only unsustainable, but are destructive of our environment, health and economic future. For many years we have invested too heavily in dangerous, pollutant and non-renewable energy forms, and only by default in alternative energy technologies and use.

Had the reverse been the case, we would not be here to-day, and it would not be of such crucial importance that this committee **research carefully, consult broadly, and set the trend for the next generations of energy consumption -one that is sustainable and protective of the citizens of Ontario and Canada, for many generations to come.**

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Dear Ontario Power Authority (OPA),

My email is in response to your drive for public input, the topic being: what kind of future power scenarios should be analyzed before developing your recommendations to the Minister of Energy for Ontario's future electricity supply mix.

Records for electricity consumption have shattered this summer as Ontarians tried to keep cool in the worst heat wave in 50 years. During the heat wave, Ontario has struggled to keep up, resorting often to importing power from the United States because the province doesn't generate enough power on its own to meet increasing demand. Energy Minister Dwight Duncan warned last week that Ontarians will have to get used to this until another 9,000 megawatts in generating capacity comes on line in two or three years.

To me, this indicates that our energy problems are becoming unmanageable, and that **the OPA must turn to conservation and renewable energy as the solution**.

The President and CEO of the Toronto Board of Trade recently stated:

"We have to safeguard the actual electricity supply and distribution system. Instability in voltage and unreliability of supply on a regular basis could drive high-tech companies, manufacturers, call centres and many others away, resulting in devastating economic and job losses for our city."

The best scenario for you to include in your recommendations would be a full phase-out of dirty coal and dangerous, expensive nuclear in the electricity sector; measures for greater efficiency and conservation programs; and insistence that any new supply should be made up of a large percentage of renewable energy, such as solar, wind and biomass power, and clean conventional power such as natural gas-fired generators, or hydro-power stations.

Ground-breaking research conducted by the Pembina Institute indicates that **it is quite possible for Ontario to get 60% of its electricity from renewable sources by 2020 while eliminating dirty coal and nuclear power.**

Again, comments from the CEO of the Toronto Board of Trade,

"Ensure an adequate supply of power at reasonable prices across Ontario. This is the provincial government's responsibility, and the only practical way for it to meet this challenge is through diversity of fuel types, technologies, sizes and locations of power plants. Our eggs are safer in many kinds of baskets across the province. We need to have an open, honest debate about what role new or improved technologies should play in our system"

In 2004, the government received 33 proposals from glean0energy generating independent power producers totaling 8,268 MW of capacity in response to its 2,500 MW Request for Proposals. Therefore these proposals alone already provide the OPA with a potential extra
5,768 MW of new clean supply capacity; almost twice what is required.

It is the OPA's responsibility to ensure that Ontario can meet its energy needs cleanly, efficiently, and economically. The best way to do this is to **introduce new, clean technologies until they make up at minimum 60 % of the supply mix, while increasing conservation and phasing out dirty coal and unreliable nuclear.**

Yours sincerely,

Anna Przychodzki
55 Seaborn Rd
Brampton, ON
L6V 2B8

Dear Ontario Power Authority (OPA),

I would like to add my input to your request for public participation in developing your recommendations to the Minister of Energy for Ontario's future electricity supply mix.

Ground-breaking research conducted by the Pembina Institute indicates that it is quite possible for Ontario to get 60% of its electricity from renewable sources by 2020 while eliminating dirty coal and nuclear power.

It is the OPA's responsibility to ensure that Ontario can meet its energy needs cleanly, efficiently, and economically. The best scenario for you to include in your recommendations would be a full phase-out of dirty coal and dangerous, expensive nuclear in the electricity sector; measures for greater efficiency and conservation programs; and insistence that any new supply should be made up of a large percentage of renewable energy, such as solar, wind and biomass power, and clean conventional power such as natural gas-fired generators, or hydro-power stations.

Yours sincerely,

Sylvia Przychodzki

Hey reducing coal smoke and nuclear waste makes sense.
By investing in wind power, solar and other old and up coming renewables the future of the planet and for people will be better. I know your worried about the jobs of the the poeple who mine coal and uranium and the jobs of people such as yourselves who run the energy plants. So heres the plan you make the changes using the energy plants you own now you build a wind turbine or solar pannel making plant near were you work and slowely get people in the coal and uranium industry intrested. Coal and uranium will both run out maybe not right away but action must surely be taken to see that we are prepared when they do.
As for the polution caused by the smoke used to make the wind turbines or solar pannels I sujest you first use it for heating then filter the worst toxins out, then trap the remaining C02 and sell it to green houses as fertizer as for the waste uranium you'de better find some safe use for it or export it to the sun it's too dangerous to be left lying around for hundreds of years unattended.

Best of luck powering the future as safely as possible Amber

Dear OPA,

I beg you to include a scenario with a minimum of 60% renewable electricity by 2020 and a full phase-out of dirty coal. This is crucial for helping to keep our ozone layer intact, and for stopping our air from being poisonous. It will also ensure a healthy, active population for years to come. This is not an option. It's to keep us alive.

Please let me know that you are planning to take progressive action on this matter and push ahead on making our energy clean and renewable.

Sincerely,

Josh Rachlis

Dear Ontario Power Authority,
I am writing to you to emphasize how important it is to halt nuclear expansion. My father, a professional geologist with over 30 years of experience, sat on the fence about nuclear energy. He has been studying the merits of secure storage in the Canadian Shield (that is not his direct specialty). He has watched the debate, read articles by other geologists. He once thought it would be safe and secure for generations to come. Given new information from fellow geologists, he is now convinced that this is not a safe long-term solution. There is too much risk in mining, refining, shipping, storing and 'disposing' of nuclear waste. The future power mix must result in a decrease in both the percentage of power delivered by dirty nuclear and in the absolute amount of nuclear waste being produced. I urge your report to recommend that the cost of electricity be high enough to pay for the cost of renewables. This will spur conservation. I see on the IESO website that electricity wholesale prices costs 12 cents to 50 cents per kilowatt hour. That means we are subsidizing homeowners who are energy hogs. I think there needs to be an energy conservation curriculum in high schools. Most people don't know how to blow in cellulose insulation, how to apply caulk, or how to install weather-stripping or even set up a clothesline. A one to four hour education component on this will save Ontarians money, especially during peak periods. And will save energy. I hope you can include my comments in your report, the most important of which is halting nuclear energy. I am disappointed that the CNA is putting out propaganda on prime time TV, and this is bound to skew your results. A wealthy lobby, it is.
Sincerely,
Melanie Ransom
Ottawa

Subject: re: Public Input into Hydro Plan

Good Morning.

Please consider supporting conservation efforts (homeowners to get soms sort of rebate if they keep their annual consumption under a certain amount?)

During the recent energy crisis, places like A & P have been using one half of their lighting and also leaving their air conditioning at a more reasonable temperature (usually it is so cold, one has to wear a jacket into the supermarket on hot days!) The reduction in their monthly hydro bills might be an incentive to continue by perhaps installing "dimmers", etc. as a way of keeping their lighting subdued somewhat -- and hopefully we can all mention to our store managers how much more comfortable the air conditioning is now.

The present public campaign to keep your home air conditioner at 26 degrees Celcius has motivated us to do just that; public education in conservation is a good idea.

Rebates on buying lightbulbs that are fluorescent (perhaps provided when people send in their packaging and store receipt?) is one other way to encourage people to buy the more expensive, but more energy efficient - lightbulbs.

Discounts or rebates on energy-appliances might be another conservation approach.

Thank you for considering this submission. sincerely, Carol Richardson.

Modelling Tools for Ontario Power System Planning

Submission to
Ontario Power Authority

Prepared by
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August 26, 2005

This submission discusses the need for modeling tools to support power system planning at the Ontario Power Authority and suggests a number of approaches and options for meeting those needs.

Power system planning, like most planning problems, is an adaptive or continuing process. Inevitably, with the passage of time, the planning assumptions or projections upon which the initial plan is based, prove to be incorrect and the plan must be adapted to fit new circumstances. This implies an on-going need for modeling tools that can be easily updated as new data become available in order to test new planning assumptions.

Models are important devices for supporting the formulation of plans and their on-going revision. For the purpose of power system planning, models can be used for exploring future trajectories of the power system that are physically coherent: both internally coherent and coherent with rest of the energy system and the factors that influence its growth. It is from the set of physically coherent trajectories that a preferred or targeted trajectory must be chosen that will meet the policy objectives. Because the selection criteria are subjective and subject to trade-offs and negotiation, it is important that the model not select a 'best' or optimal trajectory. Once the preferred trajectory has been agreed upon, policy instruments must be selected to induce the changes in behaviour that will achieve the desired trajectory. Models of behaviour that embody a theory concerning how an agent responds to policy instruments may help in choosing the appropriate policy instruments, but these models invariably rest on the assumption that future responses will resemble past responses.

Models are also useful for assessing the robustness or sensitivity of plans with respect to planning assumptions.

Perhaps, most importantly, models can play a role as a communications device: building the consensus among stakeholders that the proposed plan is necessary and sufficient to meet the policy objectives. Without this consensus, taking appropriate policy actions is often problematic.

Essential Characteristics of Planning Models

To meet these needs planning models must have a number of characteristics:

- **Transparency** - It is essential that models be understandable by all model users and stakeholders to the planning problem. It should be possible to answer the question 'why did the model produce a particular result?' by identifying the assumptions and the influence structure for every scenario. Lack of transparency may be a problem if documentation is incomplete and inaccurate, and if the model is expressed in reduced form equations and correlations such that coefficients do not correspond to natural concepts.

- **Flexibility** – Models must be designed and implemented so that new data observations, data revisions and changes to model structure can be made accurately and efficiently. Flexibility can be achieved if the model and the code that realizes it are fully documented and if a team with the capacity to implement change is maintained over time.

- **Physical Coherency** - Both energy supply and consumption options must be assessed within an integrated framework that assures the physical coherence of energy scenarios: coherence between economic growth and the energy system; coherence between sources of energy and uses for energy; coherence between the stocks of energy consuming artifacts and the fuels needed to operate them; and coherence with physical laws and technical specifications governing the technologies that transform materials and energy. Coherency is achieved through the use of supply-disposition identities that ensure coherency within a time period and stock-flow identities that ensure coherency over time.

- **Inclusiveness** - The structure of the models should be sufficiently rich that all stakeholders can explore the scenarios of interest to them or the ones they advocate.

- **Theory Neutrality** - Models should be seen as devices for exploring the implications of alternative theories of behaviour; they should not embrace only a single theory unless there is a broad based consensus of the validity of the theory. For example many current energy models incorporate consumer choice theory. While consumer choice theory can be made to fit the circumstances of the immediate past, it is not clear that it can say anything useful about choices for technologies not extant. Further, future circumstances, such as heightened awareness of climate change, urban air contamination, and peak production of conventional oil and gas, may differ from those of the past thereby invalidating the use of correlations calculated from observations of the past for future scenarios. Restricting future scenarios only to those that can be reached if the behaviour of the past persists into the future is unnecessarily limiting.

- **Consensus Building** – Models should embody only those structures and parametric data for which there is consensus among stakeholders. When consensus does nor exist, the model should be capable of incorporating alternatives. For example if there is not consensus that a particular parameter always has a specific fixed value, the parameter value should not be embedded in the code of the model; rather it should be considered a variable and given a time subscript so that model users can input values of their choice, including values that change over time, and see the sensitivity of results to that parameter. Physical coherency and inclusiveness are concepts around which it is relatively easy to build consensus. Embodiment of particular behavioural theories or objective functions may be divisive.

- **Credibility**. Models must be accepted as credible by all stakeholders. Credibility often rests exclusively on the credentials of the institution and the principal investigators. However, the more important element of credibility is model validation. Because planning models are intended for exploring the feasible region in systems whose future is influenced by the decisions of the planner, the usual test of validation, which is to see how well the model predicts the future, is not appropriate. In these kinds of models there are two validation criteria. First, the model should be able to replicate historical data, more specifically given starting values of stock variables at the beginning of an historical period, there must be settings of the control variables over the historical period such that the model tracks on the observed state variables over the historical period. Second, it must be agreed that the representation of processes in the model correspond to reality – this implies that the model must be specified in terms of concepts and relationships that are directly meaningful to the stakeholders. The first criterion of historical replication is necessary but not sufficient as there is potentially a large number of models that might meet this criterion. The second criterion, which is subjective, can only be met if the model has the properties of transparency, inclusiveness, and physical coherency such that consensus can be built. Note that, by their very nature, linear programming models cannot be calibrated and hence cannot meet the criterion of historical replication.

Suite of Models

It is suggested that the OPA will require two models for power system planning.

The first is a strategic planning model. The Ontario power system must be seen in the context of the production, trade and use of all sources of primary energy and fuels in Ontario and Canada over a time horizon that is long enough to encompass a possible transition away from conventional oil and gas. The energy system must also be put in its economic and environmental context; it must be concerned with energy independence, security of supply, green-house gas emissions and climate change, and air quality.

The second is a detailed representation of the Ontario power system - its power generating stations and transmission facilities – in terms of capacity and operations. It should keep track of installed capacity in terms of individual plants over time as new stations are put in place or as existing ones are retired or taken off-line for maintenance. It should also be able to simulate the operation of these plants to generate power to meet load curves that are subject to daily and seasonal peaks that evolve or shift over time. Its time horizon should be at least as long as the useful life of the facilities for which plans are to be made.

It is important to maintain the two models as separate entities. There will, of course, be information or scenarios that may be passed from one model to the other. A single model incorporating both long term context and a detailed representation of the Ontario power system is apt to be cumbersome to use because of the volume of detailed plant-by-plant input required for each scenario. This separation is based on our experience that models mixing short term and long term dynamics often fail to get the long term dynamics right because the long term dynamics are obscured by daily and seasonal fluctuations.

Strategic Planning Model

It is undoubtedly the case that the strategic planning model which focuses on the energy, economic and environmental context within which the Ontario power system operates will be of interest to agencies of the provincial and federal government, business enterprises, utilities, and nongovernmental organizations concerned with energy and environment. It would be beneficial that all these organizations share access to the same suite of models. However, at the present time, most models that might play this role are the property of government agencies who do not have a mandate to support access to them by all interested parties or they are the property of consulting companies or university based research organizations who sell services from them on a for-profit basis. The cost of access tends to be prohibitive for many interested parties. Further, many of these models lack transparency in order to enhance bargaining positions or to protect private property. Those models with roots in academia are often theory-rich or prescriptive. This situation is being addressed by EnergyINet, a new organization launched in March of 2005, with plans to establish an Integrated Energy Framework for Canada. This initiative may be of interest to the OPA as a means for obtaining access to an appropriate strategic planning model.

The EnergyINet Initiative

EnergyINet (http://www.energyinet.ca) is a recently launched and growing national network, designed to be a quick, agile link between today's energy challenges and the innovation of tomorrow. It brings industry, researchers and government together to unlock the next generation of ideas and technology that will provide us with an abundant supply of environmentally responsible energy that creates economic prosperity and provides governments with the revenues they need to fund important social priorities.

As a multi-government and industry driven not-for-profit organization, EnergyINet is ideally situated to facilitate the development of an integrated energy framework and ensure its accessibility to all interested parties. With its network connectedness across the energy sector, it can draw on the expertise of its member organizations to bring the latest thinking in future options, realistic transition timing and likelihood of occurrence.

The integrated energy framework will be developed in partnership with Robbert Associates Ltd and will be based on the 'physical economy' approach and the whatIf? modelling technology developed by them. A great deal of work has already been done: modules for population/macro-economic context, transportation energy end-use, fuel production, feedstock production, greenhouse gas emissions and criteria air contaminants are complete; early versions of modules for residential, commercial and industrial energy use are available. What remains is to refine each module and integrate them into a single framework.

EnergyINet is inviting organizations with an immediate need to use the integrated energy framework to become founding members of the Integrated Energy Framework project. Founding members will share the cost of completing the framework and will participate in reviewing and refining the modules. In this way, founding members can be assured that the framework has sufficient structure to explore options of interest to them.

The total cost of completing the development of the Integrated Energy Framework is $500,000. It is planned that it would be completed, tested and available for use by end 2006. Accordingly the share of cost to be borne by each founding member should be less than $100,000.

Once the Integrated Energy Framework is in place, it will be made available to interested organizations on the principle of cost recovery.

A version of the EnergyINet Integrated Energy Framework is now available for demonstration as proof-of-concept. It consists of modules for transportation energy use and emissions and fuel and feedstock production.

Ontario Power Systems Model

As OPA is the agency with primary responsibility for power system planning in Ontario, it is clear that it will have to lead in developing a power systems Model for Ontario. Such a model will have three main components; one for the allocation of provincial demand for electricity to regions and time of day, one for electricity generation, and the other for interregional transmission. The last two components interact and must be tightly coupled insofar as both requirements for power and generating capacity are distributed in space and it follows that the allocation of demand to generating facilities is subject to the capacity of the interregional transmission facilities.

Two sets of options exist for the OPA.

One set is concerned with the degree to which OPA contracts out or uses its staff to develop, maintain, use, and support use by others. These range from:

1. Developing the capacity in-house to design, implement, and operate models with little or no contracting out
2. Developing the capacity in-house to maintain and operate models but contracting out for model development and staff training
3. Developing the capacity in-house to operate models but contracting out for model development and staff training and model maintenance.
4. Contracting out for model development, model maintenance, and model operation with little in-house or no capacity

It is our experience that in-house modelling teams in government organizations charged with developing and operating a single model are seldom effective. Not only is it difficult to recruit experienced modelers, but the team has to be a minimum of three to four people to assure continuity. Staff turn-over, cost, and availability of experienced staff make option 1 difficult. Option 4 is equally unattractive; it is essential that some staff are sufficiently knowledgeable about models that they can interpret results, understand the strengths and weaknesses of model based results, and control the contracting out process. Some of this knowledge comes from participation in the model design process. Options 2 and 3 differ only in whether model updating and maintenance is contracted out or not. On balance we believe that model maintenance should be contracted out both to assure the on-going availability of the model and the relevance of its structure as new circumstances arise.

The second set of options concerns the degree of customization; there are essentially two options:

1. Acquire an existing model from a company that has a model on the shelf that seems to meet needs. Such models are designed in such a way that they can be applied to different utilities or areas ‘simply’ by supplying the appropriate data set.
2. Acquire a custom model designed specifically to meet the needs of the organization.

Option 1 is often preferred because it is (mistakenly) perceived that risks associated with model development would be avoided. The cost of the risk avoidance, namely loss of needed functionality, is thought to be acceptable. However, we strongly recommend Option 2 for many reasons:

- It is our experience that only ten to fifteen per cent of the cost of developing a model is associated with the code that represents the structure or equations of the model. Most of the cost is in data preparation and calibration and this cost is

specific to each instance of the model. Not much is saved in reusing this code, but the cost in terms of lost functionality may be very high.

- Models available in Option 1 very often lack transparency – in order to protect the intellectual property of its developer.

- Models available in Option 1 very often are inflexible: either they are hard-coded in Fortran , C, or visual basic over a data base facility, with data values imbedded in the code, with output limited to a few fixed format reports or they are implemented in a modeling package oriented to a particular mathematical paradigm – usually linear programming or system dynamics.

- Option 2 offers the possibility for staff of the organization to participate in model design that is essential if the model is to be wisely used.

The experience of the Robbert Associates modelling team[1] enhanced by the power of the whatIf? modelling technology[2] make the development of custom models both cost effective and efficient. The risk of cost over-runs and extended time schedules usually associated with model development projects is eliminated. Once a design has been agreed upon, Robbert Associates will quote a fixed price for implementation and guarantee a delivery schedule.

The whatIf? modelling technologies were designed to realize the lessons learned from extensive experience in model development. These lessons are expressed in the following modelling philosophies:

- Documentation, the key to achieving transparency, must be an integral part of model development. In the whatIf? environment, model documentation and model implementation are built from common input – thereby assuring that accurate and up-to-date documentation is always available. Documentation is layered. The top two layers are diagrammatic: the first identifies sub-models; and then sub-models are represented in terms of variables, procedures and connective structures with English language descriptions and meta-data. The third level of documentation is the TOOL language code that realizes each procedure. The TOOL component of the whatIf? software suite is a mathematical language resembling subscripted algebra that serves as both the mathematical statement of the model and the code

[1] Over the past 15 years, Robbert Associates has developed more than fifty custom simulation models in a wide range of problem domains. This experience includes the EDM energy demand and the CANPLAN electricity generation models for the National Energy Board, the CanTEEM transportation energy and emissions model for the Transportation Energy Use Division, NRCan and the Office of Sustainable Technologies, NRC, and a suite of energy end use data bases and simulation models for the Demand Policy Analysis Division at NRCan.

[2] The whatIf?® modeling technology was developed by Robbert Associates. It is a suite of software tools that supports the design, documentation, implementation, and calibration and operation of large scale simulation models. It provides full facilities for scenario analysis interactive data analysis.

that realizes it. The fourth level is detailed documentation for each of the approximately 150 TOOL language operators.

- Data values for all variables and for all scenarios must be seeable in tabular and graphic format. The TOOL language has facilities for interactive display of multi-dimensional arrays. The SAMM (Scenario and Model Manager) component of whatIf? has unique and powerful facilities for creating, displaying and comparing scenarios and managing the underlying data.

- Data compilation, cleaning and updating are the most labour intensive and costly components of model development. Unlike other modeling software, the whatIf? suite provides full facilities to support them. The approach supported by whatIf? is to implement a formal calibration model. The calibration model takes as input the raw observed data sets and the rules for imputing missing data and enforcing consistency; it produces as output historical values for all of the variables of the simulation model that are consistent with the accounting identities. The simulation model and the calibration models are linked in such a way that the calibration model provides the starting values of the stock variables and historical values for all variables in the simulation model. Not only does this approach provide rigorous documentation for the data cleaning procedures, but it also facilitates incorporating data revisions and updates.

- The logic of the core model should be separable from the reporting of results and the preparation of values for control variables. It is our experience that as models are used over time and by different users the requirements for reporting grow significantly. In a mature model, for every line of code of model logic, there may be ten lines of reporting code. The whatIf? software supports the concept of views - TOOL language programs that implement various ways for preparing data input and reporting model results.

- It is desirable to separate physical transformation processes - those that transform materials and energy – from those that transform information. Because physical transformation processes must obey the physical laws of mass conservation and thermodynamics, coherency among them and consensus can be achieved. Representations of physical transformation processes should form the core of the model. Decision rules are embedded in information transformation processes. The output of these processes may be settings of the control variables associated with physical transformation processes. Representations of information transformation processes may be separate sub-models or they may reside in the viewing system. This approach facilitates the inclusion of alternative behavioural theories in the model.

Summary of Suggestions

1. For the purposes of power system planning, the OPA requires two models: a strategic planning model encompassing supply and uses of all fuels and energy feedstocks in Ontario and Canada, and; an Ontario power systems model focusing on power generation and transmission facilities in detail.
2. These models should have the properties of transparency, inclusiveness, physical coherence, flexibility, theory neutrality and credibility in order to support consensus building among stakeholders.
3. With respect to the strategic model, the OPA should consider becoming a founding partner of the EnergyINet Integrated Energy Framework project in order to share with other partners the cost of developing and maintaining this model.
4. The OPA should consider putting in place and training staff resources to have the knowledge and expertise to operate the models to create planning scenarios effectively.
5. The OPA should contract out for the development and on-going maintenance of an Ontario Power Systems model custom designed to meet its specific circumstances and to complement the strategic model.

Faculty of Environmental Studies
University of Waterloo
Waterloo, ON
N2L 3G1

26 August 2005

Ontario Power Authority
supplymixsubmissions@powerauthority.on.ca

To Whom It May Concern:

Re: Call for Written Submissions.

I write to contribute to the discussion regarding the supply mix for Ontario.

In response to the Minister's requests, I believe that any consideration of the future supply mix in Ontario should prioritise conservation, followed by renewable resources, followed by conventional resources. In any case, evaluation of options should be on the basis of sustainability criteria.

In response to the OPA's four 'issue areas', I offer reference to four pieces of work that I have recently completed. I believe that they have the potential to contribute to the kinds of detailed analysis that the OPA is seeking.

1) Ian H. Rowlands, 'Solar PV Electricity and Market Characteristics: Two Canadian Case-Studies', *Renewable Energy* ((Vol. 30, No. 6, May 2005), pp. 815-34.

   This article determines the potential value of solar electricity in meeting peak demand and peak price periods in the Ontario electricity marketplace.

2) Ian H. Rowlands, 'Envisaging Feed-in Tariffs for Photovoltaic Electricity: European Lessons for Canada', *Renewable & Sustainable Energy Reviews* (Vol. 9, No. 1, February 2005), pp. 51-68.

   This article analyses the potential costs and benefits associated with a feed-in tariff scheme for solar electricity in the Ontario electricity marketplace.

3) Ian H. Rowlands, 'Why We Need Renewables', *Alternatives* (Vol. 30, No. 1, Winter 2004), p. 19.

   This brief article highlights the important contribution of energy efficiency while nevertheless arguing that renewable resources ultimately need to be deployed in energy systems.

4) Ian H. Rowlands, 'Ontario Demand Response Scenarios'.

   This report (executive summary and table of contents attached) aims to contribute to discussions regarding electricity challenges in Ontario by presenting and

describing two scenarios involving different strategies for demand response. A full copy of the report will be available in early September.

Copies of three of these four articles are attached. Please note that copyright regulations allow me to 'make copies and distribute copies (including through e-mail) of the article to research colleagues, for the personal use by such colleagues (but not commercially or systematically, e.g. via an e-mail list or list serve)'. It is in this spirit that I attach these copies.

Please note that I make these comments in a personal capacity and do not claim to represent any particular organisation.

Of course, please let me know if you require any clarifications or further information.

Sincerely yours,
Ian H. Rowlands

Ian H. Rowlands
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Subject: Ontario power supply

Importance: High

It is my wish/hope that Ontario becomes a world leader in the generation of renewable clean electrical power. I am pleased to hear of the new windmill and hydro projects around the province and the plan to phase our dependency on coal. I wish that Ontario would also completely eliminate our use of nuclear power ASAP and move to a truly clean production of energy.

I live in the town of Whitby in between two nuclear power plants that continually prove to be inefficient, very costly and a huge long term hazard. Long after this study is completed, the danger from the nuclear waste, which we have already created, will still remain.

Somewhere in this great province the wind will always blow, the sun will shine, water will flow and gases will escape from our garbage dumps. It is our responsibility to increase our use of truly clean power to ensure that the legacy we leave will be one we can be proud of.

The Pembina Institute indicates that it is quite possible for Ontario to get 60% of its electricity from renewable sources by 2020 while eliminating dirty coal and nuclear power. I therefore recommend that we get a MINIMUM of 60% of Ontarios electricity from renewable resources by 2020 and continue to eliminate dirty coal and completely phase out unreliable nuclear power.

Please keep me informed of your discussions and decisions.

Sincerely
Darren Ruddock

SARNIA LAMBTON
Chamber
OF COMMERCE

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AUG 2 6 2005

August 25, 2005

Ontario Power Authority
Supply Mix Submissions
175 Bloor St. E.
North Tower, Suite 606
Toronto, Ontario
M4W 3R8

Re: Written Submission on Supply Mix

The Sarnia Lambton Chamber of Commerce would like to request that in the near future, coal or coke gasification energy generation projects be built in Ontario. For over ten years, demonstration and operating gasification electricity plants have existed in the USA and around the world. It is time that Ontario embraced the potential of this new technology to replace dependence on natural gas generation.

Gasification technology creates the ability to use biomass, municipal wastes, coal or Ontario feedstock like petroleum coke, etc. to produce electricity, steam, hydrogen, and sulphur; all reusable products marketable in our economy.

Capturing the mercury, CO2, sulphur oxides and a reduced nitrous oxide means environmental impacts are far less than with current coal and natural gas generation. The elimination of particulate matter in the air also improves emissions.

Gasification technology may be useful for free-standing new site construction or in conversion of existing government coal fired plant infrastructure scheduled for closure by Ontario in 2007 and beyond. Gasification plants should be quicker to build than nuclear and assist Ontario to achieve its energy production goals more quickly. In addition they can be designed for load following which is significant to meet the daily demand swings in the Province

Sincerely;

Sheryl Bovay
Chair, Board of Directors

Garry McDonald
President

Attachments: USA DOE information
EPRI Gasification Outline
AERI Gasification

The Collective Voice of Business

Quoting below from the USA Department of Energy website:

www.fe.doe.gov/programs/powersystems/gasification/

Coal gasification offers one of the most versatile and clean ways to convert coal and coke or other carbon feedstock into electricity, hydrogen, and other energy forms.

The first coal gasification electric power plants are now operating commercially in the United States and in other nations, and many experts predict that coal gasification will be at the heart of the future generations of clean coal technology plants for several decades into the future. For example, at the core of the U.S. Department of Energy's *FutureGen* power plant of the future will be an advanced coal gasifier.

Rather than burning coal directly, gasification breaks down coal - or virtually any carbon-based feedstock - into its basic chemical constituents. In a modern gasifier, coal is typically exposed to hot steam and carefully controlled amounts of air or oxygen under high temperatures and pressures. Under these conditions, carbon molecules in coal break apart, setting off chemical reactions that typically produce a mixture of carbon monoxide, hydrogen and other gaseous compounds.

Gasification, in fact, may be one of the best ways to produce clean-burning hydrogen for tomorrow's automobiles and power-generating fuel cells. Hydrogen and other coal gases can also be used to fuel power-generating turbines or as the chemical "building blocks" for a wide range of commercial products.

The USA Energy Department's Office of Fossil Energy is working on coal gasifier advances that enhance efficiency, environmental performance, and reliability as well as expand the gasifier's flexibility to process a variety of coals and other feedstocks (including biomass and municipal/industrial waste).

Environmental Benefits

The environmental benefits stem from the capability to achieve extremely low SOx, NOx and particulate emissions from burning coal-derived gases. Sulfur in coal, for example, emerges as hydrogen sulfide and can be captured by processes presently used in the chemical industry. In some methods, the sulfur can be extracted in either a liquid or solid form that can be sold commercially. In an integrated gasification combined-cycle plant, the syngas produced is virtually free of fuel-bound nitrogen. NOx from the gas turbine is limited to thermal NOx. Diluting the syngas allows for NOx emissions as low as 15 parts per million. Selective Catalytic Reduction (SCR) can be used to reach levels comparable to firing with natural gas if required to meet more stringent emission levels.

The USA Office of Fossil Energy is also exploring advanced syngas cleaning and conditioning processes that are even more effective in eliminating emissions from coal

gasifiers. Multi-contaminant control processes are being developed that reduce pollutants to parts-per-billion levels and are effective in cleaning mercury and other trace metals in addition to other impurities.

Coal gasification may offer a further environmental advantage in addressing concerns over the atmospheric buildup of greenhouse gases, such as carbon dioxide. If oxygen is used in a coal gasifier instead of air, carbon dioxide is emitted as a concentrated gas stream. In this form, it can be captured more easily and at lower costs for sequestration. By contrast, when coal burns or is reacted in air, 80 percent of which is nitrogen, the resulting carbon dioxide is much more diluted and more costly to separate from the much larger mass of gases flowing from the combustor or gasifier.

Efficiency Benefits

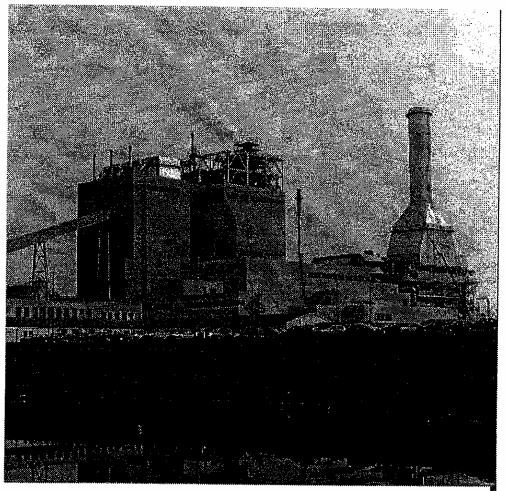
Efficiency gains are another benefit of coal gasification. In a typical coal combustion plant, heat from burning coal is used to boil water, making steam that drives a steam turbine-generator. Only a third of the energy value of coal is actually converted into electricity by most combustion plants, the rest is lost as waste heat.

A coal gasification power plant, however, typically gets dual duty from the gases it produces. First, the coal gases, cleaned of impurities, are fired in a gas turbine - much like natural gas - to generate one source of electricity. The hot exhaust of the gas turbine is then used to generate steam for a more conventional steam turbine-generator. This dual source of electric power, called a "combined cycle," is much more efficient in converting coal's energy into usable electricity. The fuel efficiency of a coal gasification power plant can be boosted to 50 percent or more.

Future concepts that incorporate a fuel cell or fuel cell-gas turbine hybrid could achieve efficiencies nearly twice today's typical coal combustion plants. If any of the remaining waste heat can be channeled into process steam or heat, perhaps for nearby factories or district heating plants, the overall fuel use efficiency of future gasification plants could reach 70 to 80 percent.

Higher efficiencies translate into more economical electric power and potential savings for ratepayers. A more efficient plant also uses less fuel to generate power, meaning that less carbon dioxide is produced. In fact, coal gasification power processes under development by the Energy Department could cut the formation of carbon dioxide by 40 percent or more compared to today's conventional coal-burning plant.

The capability to produce electricity, hydrogen, chemicals, or various combinations while eliminating nearly all air pollutants and potentially greenhouse gas emissions makes coal gasification one of the most promising technologies for the energy plants of tomorrow.



Coal Gasification
Technology & Commercialization Overview

Dr. Jeffrey N. Phillips *(jphillip@epri.com)*
Advanced Coal Generation Project Manager
Electric Power Research Institute

EPRI

Outline

- What is coal gasification?
- How does an IGCC work?
- Cost comparison: IGCC vs other fossil options
- Overview of existing coal IGCC installations
- Overview of other coal gasification installations
- IGCC research, development & demonstration needs

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What is coal gasification?

- Similar to combustion but with less than half the amount of oxygen needed to fully burn the coal
  - Combustion: excess air
  - Gasification: excess fuel
- Usually done at higher pressure (>2.5 MPa) and with high purity O2 rather than air
  - Reduces size of downstream processing equipment
  - Decreases amount of coal that must be fully oxidized to generate the temperature needed to drive the gasification reactions
  - Increases the heating value of the produced syngas

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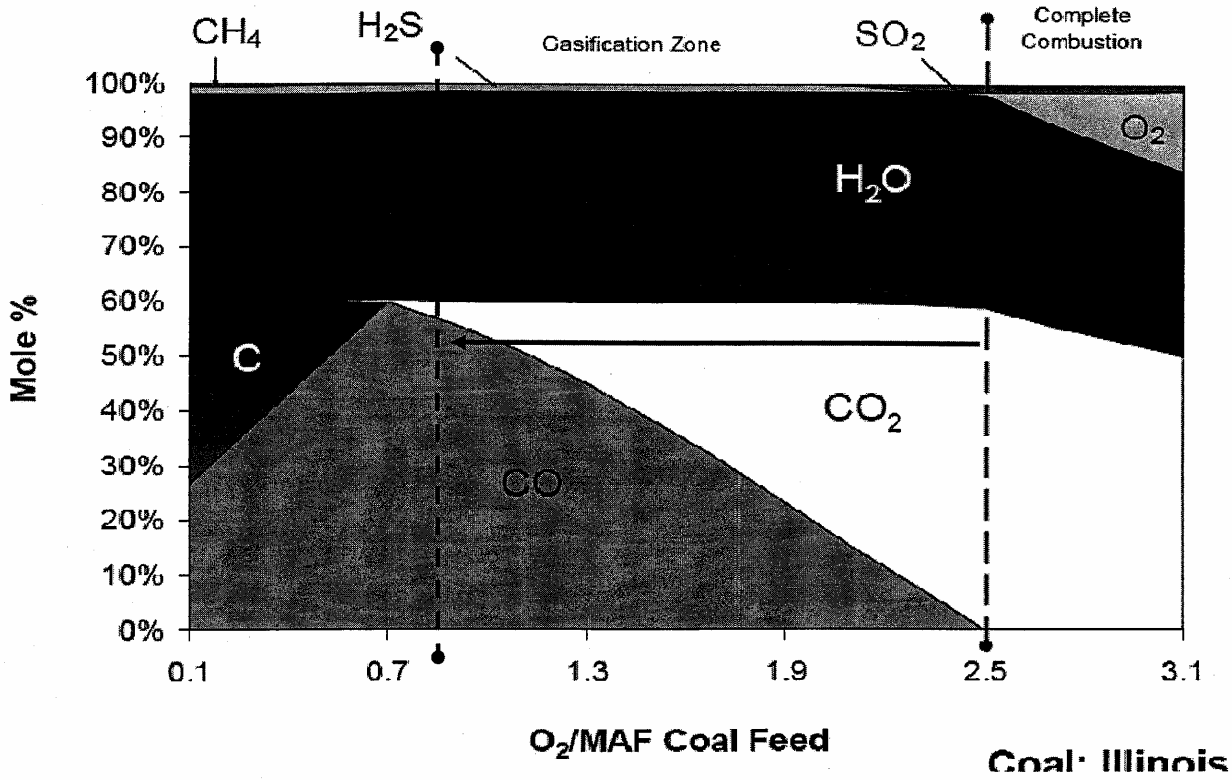
Combustion & Gasification Products



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EPRI

IGCC Environmental Attributes

- Sulfur is removed (99.5-99.99%) from syngas as a saleable product (sulfur cake)
- NOx emissions are controlled by removing fuel-bound nitrogen with a water wash upstream and by flame temperature modulation via diluent addition in the gas turbine
- Particulates are removed from the syngas by filters and water wash upstream of turbine so emissions are negligible
- Mercury and other HAP's removed from the syngas by absorption in activated carbon bed
- Water use is lower than conventional coal
- Byproduct slag is vitreous and inert and often salable
- CO_2 under pressure takes less energy to remove than from PC flue gas at atmospheric pressure

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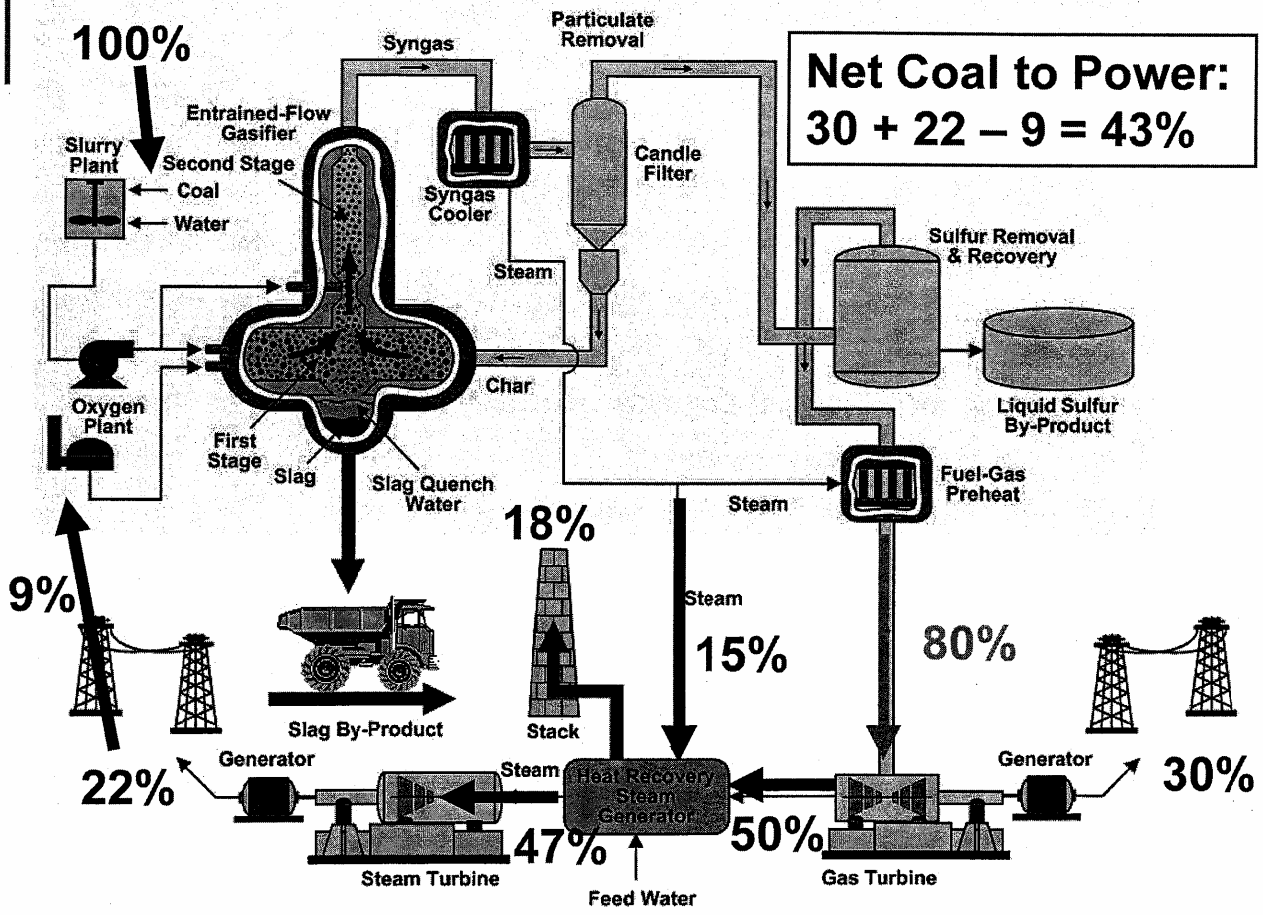

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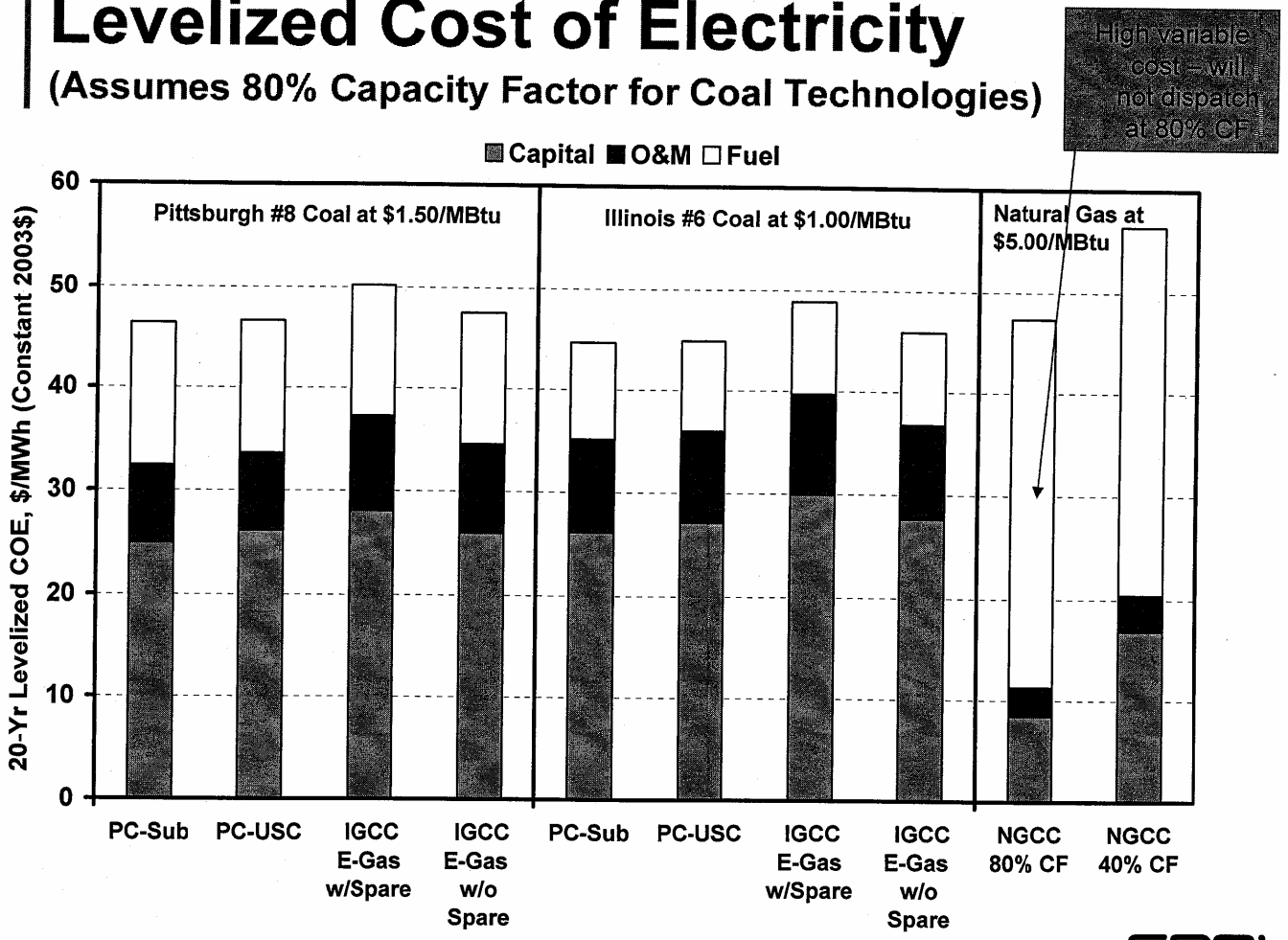
Levelized Cost of Electricity

(Assumes 80% Capacity Factor for Coal Technologies)



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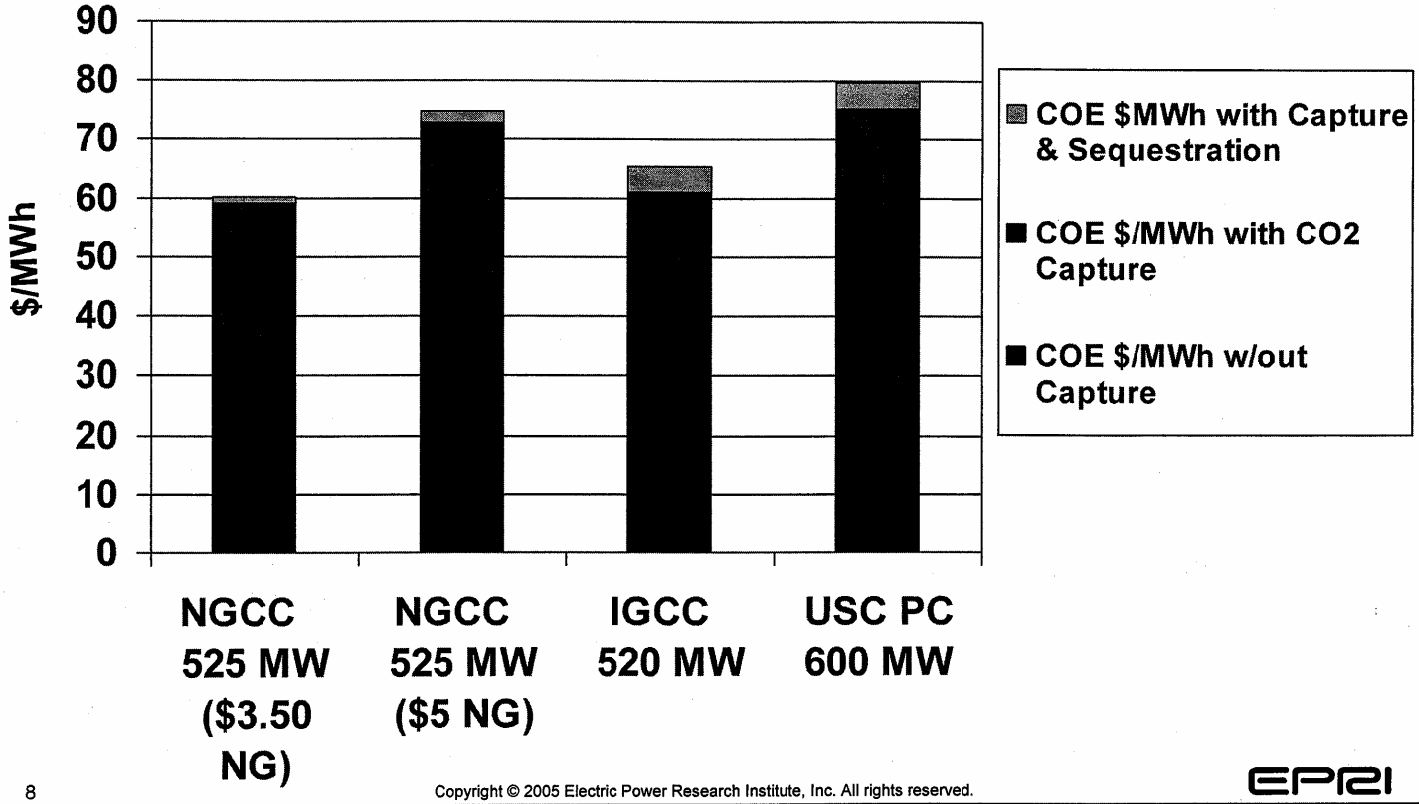
EPRI

Costs of Electricity from New Fossil Fuel Power Plants with & without CO2 Capture



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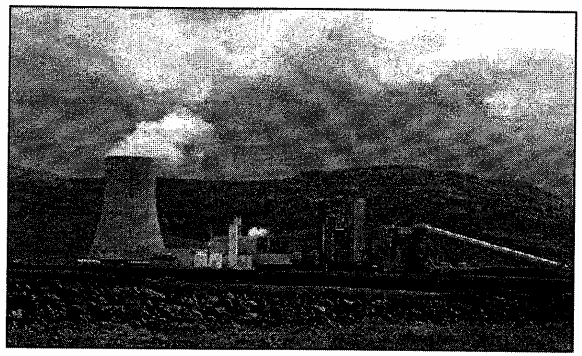
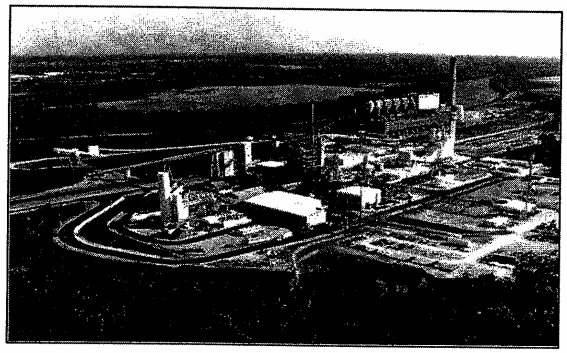
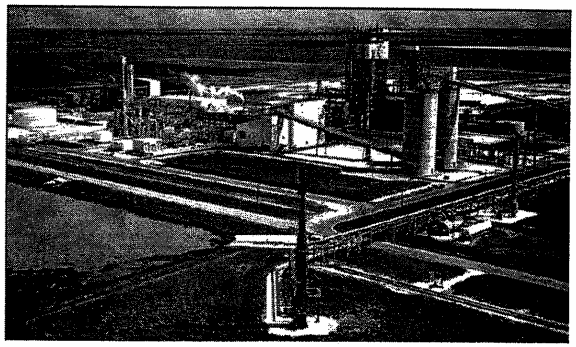
Existing Coal-based IGCCs



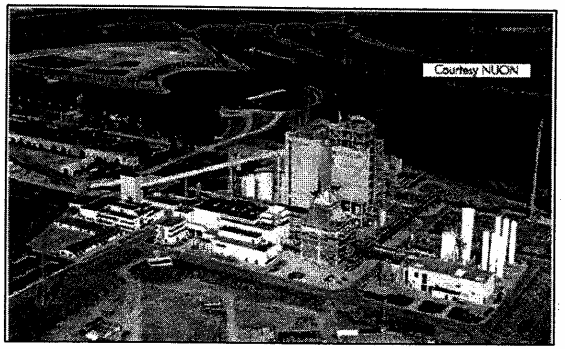
Puertollano (Spain)



Wabash (Indiana)



Polk (Florida)



Buggenum (NL)

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Coal Based IGCC Plants

Project/ Location	Combustion Turbine	Gasification Technology	Net Output MW	Start-Up Date
Nuon Buggenum Netherlands	Siemens V 94.2	Shell (Offered jointly with Krupp-Uhde)	253	Jan 1994
Wabash River, IN	GE 7 FA	E Gas (ConocoPhillips)	262	Oct 1995
Tampa Electric, FL	GE 7 FA	Texaco (GE Energy)	250	Sept 1996
ELCOGAS Puertollano Spain	Siemens V 94.3	Prenflo (Offered jointly with Shell)	300	Dec 1997

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Salient Characteristics of Major Gasification Technologies

Technology Name/ Design Feature	GE Energy (formerly Texaco)	E-Gas (ConocoPhillips)	Shell
Feed System	Coal in Water Slurry	Coal in Water Slurry	Dry Coal. Lock Hopper & Pneumatic Conveying
Gasifier Configuration	Single Stage Downflow	Two Stage Upflow	Single Stage Upflow
Gasifier Wall	Refractory	Refractory	Membrane Wall
Pressure (psig)	500-1000	Up to 600	Up to 600
Notes	Offered as Quench or with Heat Recovery	Currently only offered with Heat Recovery	Currently only offered with Heat Recovery

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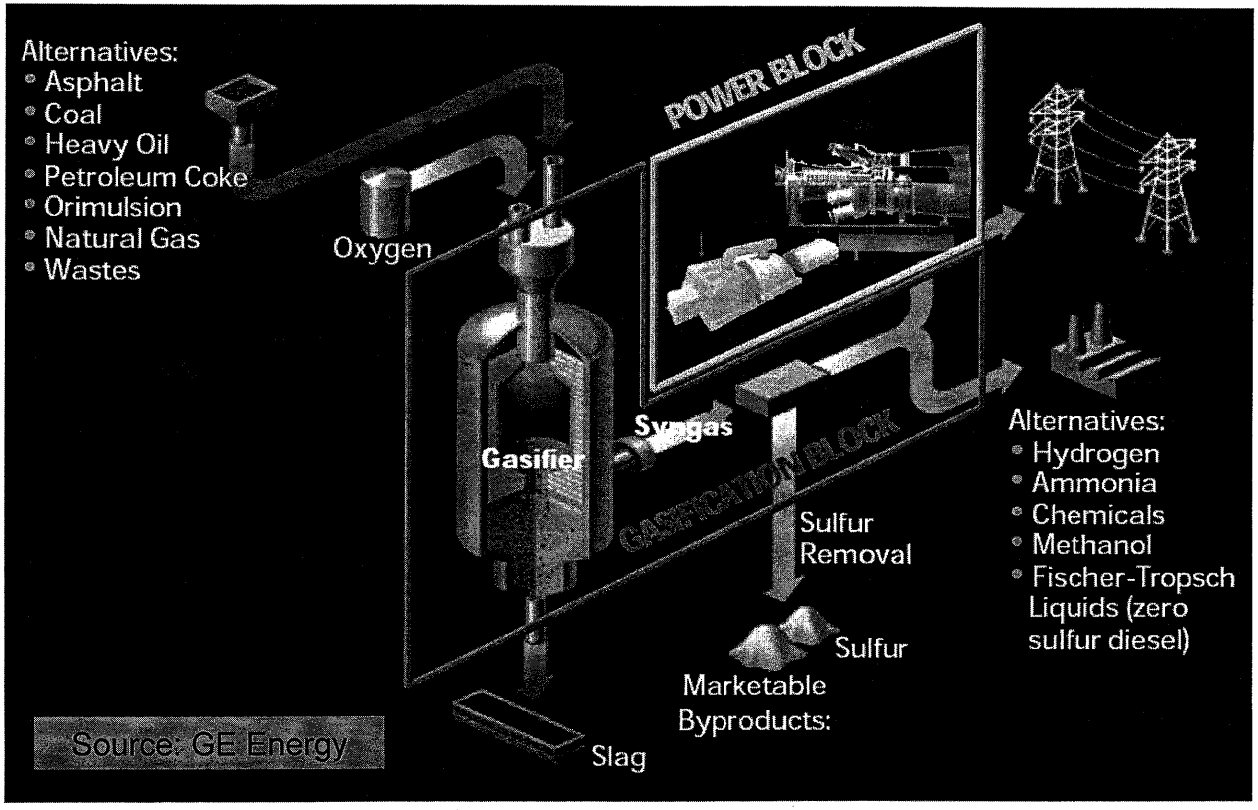
GE Energy Quench Gasifier



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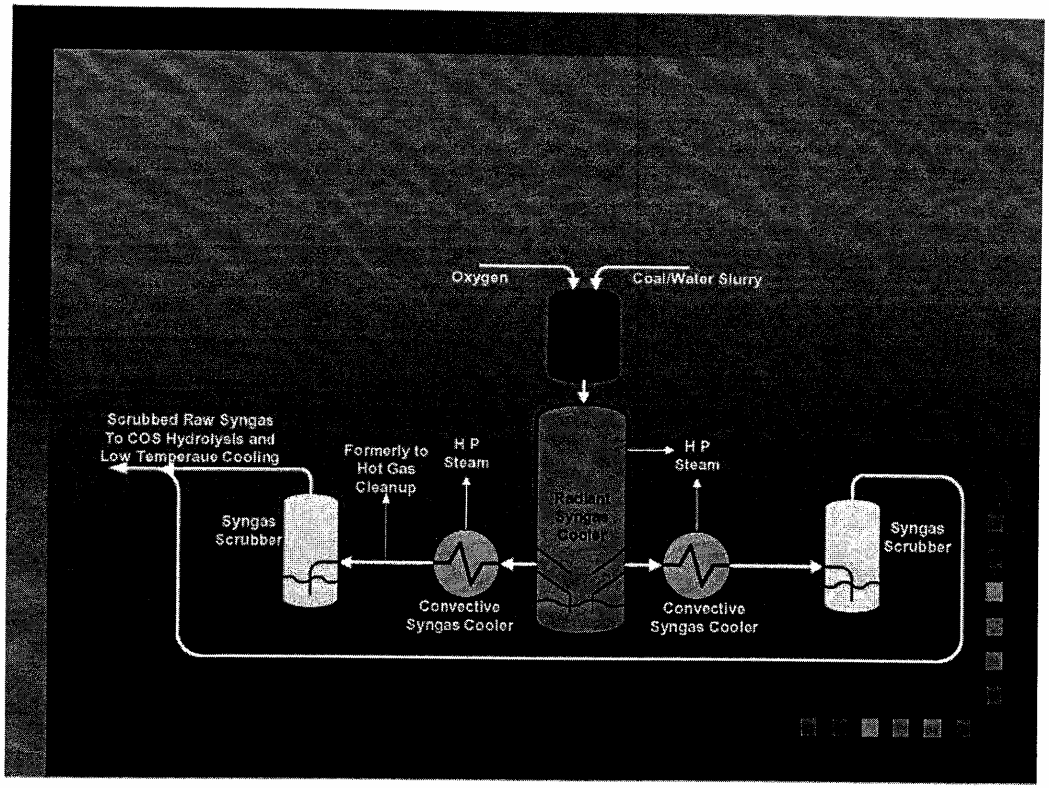
Tampa Electric – Gasification Arrangement



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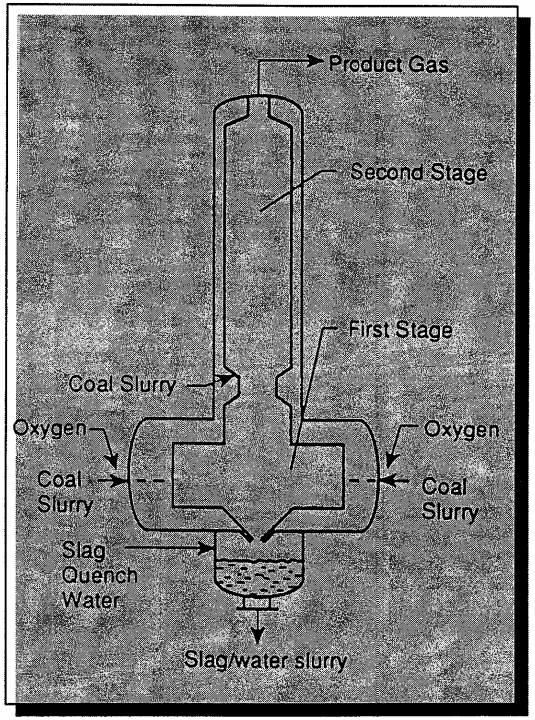
E-Gas Gasifier—As used at Wabash IGCC (Technology now owned by ConocoPhillips)



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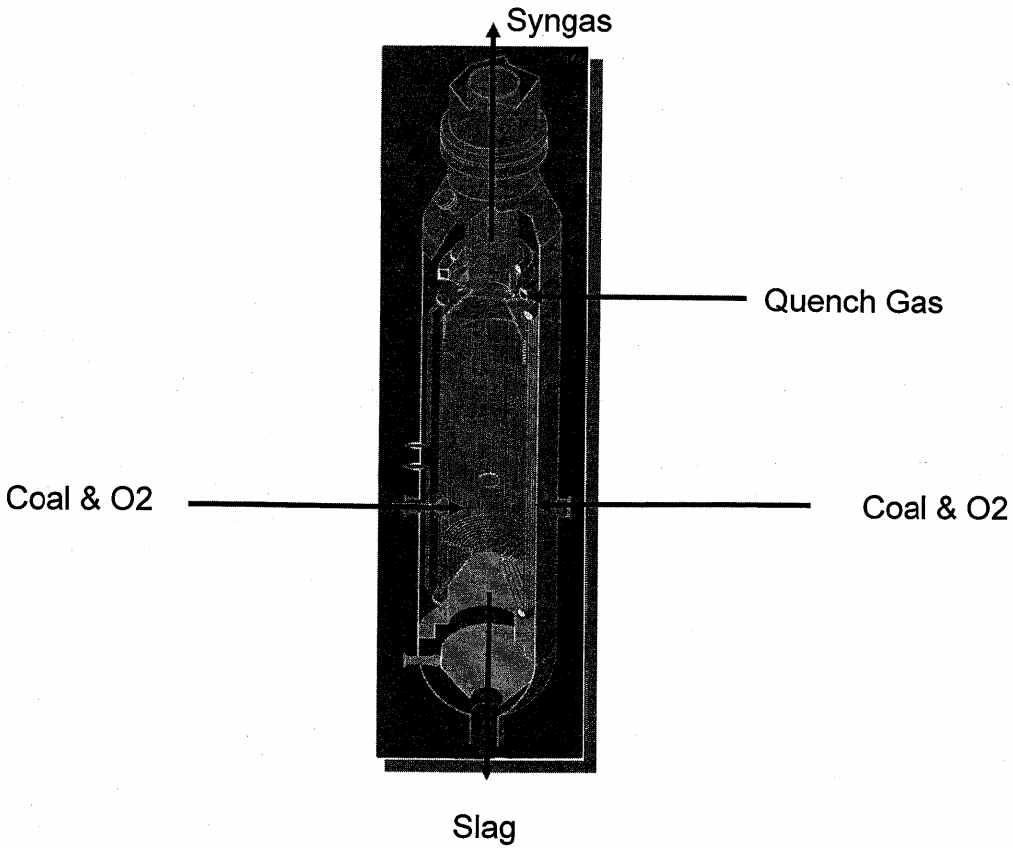
Shell Gasifier Cutaway



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Coal IGCC- Historical Causes of Outage

Project/Cause	Wabash	Tampa	Nuon	ELCOGAS
Coal Feeding	No	Minor	Minor	Yes
Injector Tip Life	90 days	60-90 Days	> 1 year	> 1 year
Refractory Wear	~ 2 years	~ 2 years	Not significant	Not significant
Slag Tap Blockage	Yes	Yes	No	Yes
Circ. Slag Water Erosion/Corrosion	Minor	Yes	Yes	Yes
Syngas Cooler Fouling	Yes – but can clean in situ	Radiant – No Convective – Yes	Minor – Rappers work well	Yes – but has not been major outage cause
Candle Filter Failure	Yes – but improved	Not applicable	No	Yes
Gas Turbine Vibration	No	No	Yes – but improved	Yes – improved but fuel switch is problematic

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Other Gasification Plants with Operating Experience Relevant to Coal-based IGCC

- Eastman Chemical, Kingsport ,TN. 2x1300 tpd GE Quench gasifiers (1 op. + 1 Spare) operating since 1983. Mercury removal > 90% from syngas. Methanol and other chemical production. Eastman offers O&M services for IGCC.
- Ube Ammonia, Japan 4x500 tpd GE Quench gasifiers. Now use pet.coke. Ammonia production.
- SVZ Schwarze Pumpe, Germany. Noell gasifier. BGL gasifier. GE 6 B. Waste gasification.
- SUV Czech Republic. Two GE 9E CT's.
- Dakota Gasification 175 million SCFD SNG (2100 MWth equivalent). Clean up and Compression of CO_2 from coal gasification plant.

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Texaco (now GE) Coal Gasification Plants in China

(Note: All Ammonia plants include CO_2 removal from the Syngas)

Location/Owner	Size mt/d	Product	Start up
Lunan	3x350	Ammonia	1993
Weihe	3x550	Ammonia Urea	1996
Shanghai Coking and Chemicals	2x550	Towns Gas Methanol Acetic Acid	1995
Huainan	3x350	Ammonia	2000

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Shell Coal Gasification Projects in China

(Note: All Ammonia plants will include CO_2 removal from the Syngas)

Location	Owner	Size mt/d	Product	Start up
Guangxi	Liuzhou Chemical	1200	Ammonia, Oxo	2005
Hubei	Shuanghuan Chemical	900	Ammonia	2005
Hubei	Anqing Sinopec	2000	Ammonia	2005
Liaoning	Dahua Chemical	1100	Methanol	2006
Yunnan	Yuntianhua	2700	Ammonia	2006
Yunnnan	Yunzhanhua	2700	Ammonia	2006
Inner Mongolia	Shenhua	2x2250	H_2 for Coal Liquefaction	2006
Henan	Yoncheng Chemical	2150	Methanol	2007

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World Gasification Survey 2004

- 117 Operating Plants, 385 Gasifiers
- Capacity – 45,925 MWth
- Feedstocks - 49% Coal, Petroleum Residuals 36%
- Products – Chemicals 42%, Fischer-Tropsch 36%, Power 19%
- Growth Forecast 5% per annum

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Worldwide IGCC Experience

- Four coal based IGCC plants Tampa, Wabash, Buggenum and Puertollano.
- Eight operating IGCC plants based on Petroleum Residuals. Three more in construction. These plants represent considerable additional commercial operating experience for the many components that are common with coal based IGCC plants (ASUs, Gas clean up, Sulfur recovery, Combined Cycles, SCR etc).
- Cumulative Combustion Turbine experience on a wide variety of syngas compositions and heating values (range 100-350 Btu/SCF) is well over a million hours.

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IGCC R&D Needed

- Dry coal fed gasifiers need lower cost coal pressurization system (not lock-hoppers)
- New feed systems for slurry fed gasifiers to improve gasifier efficiency particularly for low rank coals. (e.g. flash drying, CO_2 slurry)
- Lower energy intensity coal drying methods (for dry feed gasifiers)
- More reliable thermocouples and temperature measurement
- Longer life gasifier refractory
- Longer gasifier feed injector life (slurry feed only)
- Improved materials for syngas coolers (lower cost, improved reliability)

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IGCC RD&D Ideas (cont.)

- On line pH measurement in circulating slag/ash loops
- On line slag analyses
- Investigate syngas & water vapor equilibrium properties in quench gasifier conditions
- Determine fate of trace elements (to support permitting)
- Simplified H2S removal with elimination of Claus plant
- Understand impact of syngas combustion on CT hot section metal temperatures and identify methods to mitigate de-rating of firing temperature on syngas
- IGCC dynamic models & adaptation for operator training
- Validate sequestration of CO2

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Innovation in Alberta

Alberta Industrial Heartland
Synergy Luncheon

March 2005, 2005

Duke du Plessis
Alberta Energy Research Institute

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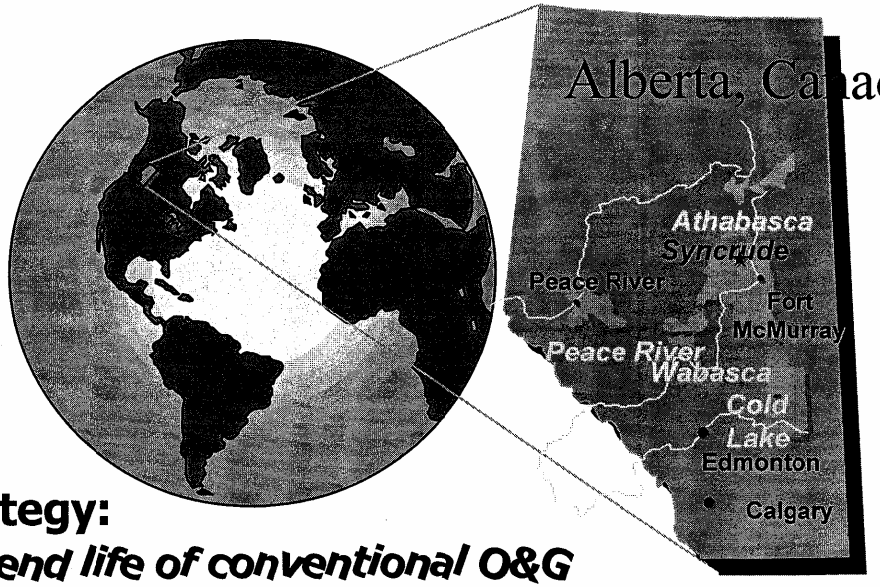
Alberta's Energy Resources

Resources	Oil	Gas	Bitumen	Coal	CBM
	Million m3	Million m3	Million m3	Mill tonnes	Million m3
Remaining Reserve	291	1,211	27,810	34,000	>3,600
Annual Production	44	141	100.23*	34	
Remaining Life	**7**	**9**	**580**	**1000**	



Strategy:

- ***Extend life of conventional O&G***
- ***Unlock abundant bitumen, coal and CBM***
- ***Add value and increase market options and profitability through a focus on integrated energy systems.***

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Major Technical Challenges

- Natural gas substitution
  - Production costs of steam, hydrogen, and NGL's affected by rising cost of natural gas
- Cleaner coal/coke utilization
- Improved recovery processes
  - Significant portion of resources not currently economic
- Improved refinery conversion technologies
  - Value of bitumen derived products - future fuel requirements and refinery specifications
- "Access to resources" – air emissions, land access and water management
- CO_2 emissions
  - Carbon capture and storage

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Other Challenges

- Overcoming technology risks
- Investor confidence
- Public perception
- Quantification and buy-in of benefits
- Innovative approaches to working together

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Energy Innovation Network (EnergyINet)

Vision:

An abundant supply of environmentally responsible energy, creating economic prosperity and social well-being for Canadians.

Key Operating Principles:

- Integration – opportunities that emerge when energy sector is viewed as an interconnected whole
- Collaboration – avoiding fragmentation and achieving shared goals

EnergyINet

EnergyINet Focus

- **Innovation Programs**
  - Oil Sands Upgrading
  - Clean Carbon/Coal
  - Improved Recovery
  - Alternative and Renewable Energy
  - CO_2 Management
  - Water Management

- **Cross-Cutting Initiatives**
  - Capacity building
  - Global Intelligence
  - Strategic Communications
  - Technology Commercialization

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High Priority Technology Platforms Impact Several Strategic Areas

Platform Techno - logies	Strategic Areas					
	Clean Coal/Carbon	Upgrading Technology	Carbon Management	Improved Recovery	Water Management	Alternative Energy
Geological Storage of CO_2						
Gasification						
Catalysis						
Hydrogen Technol						
Separ ation Technol & Solv Deash						
In Situ Technol						
Water Treatment Technol						

	Indicates Major Impact		Indicates Secondary Impact		Minor Impact

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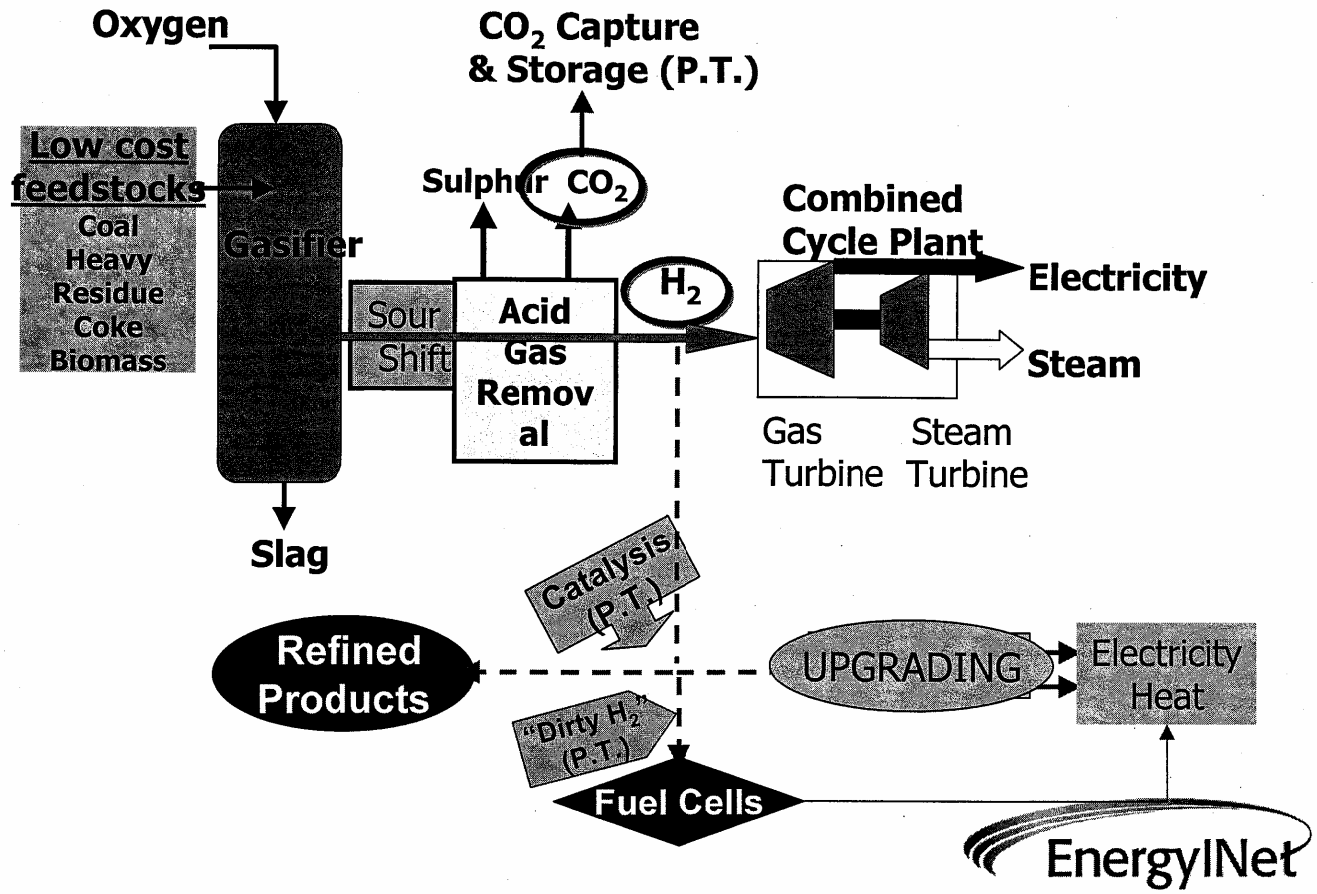
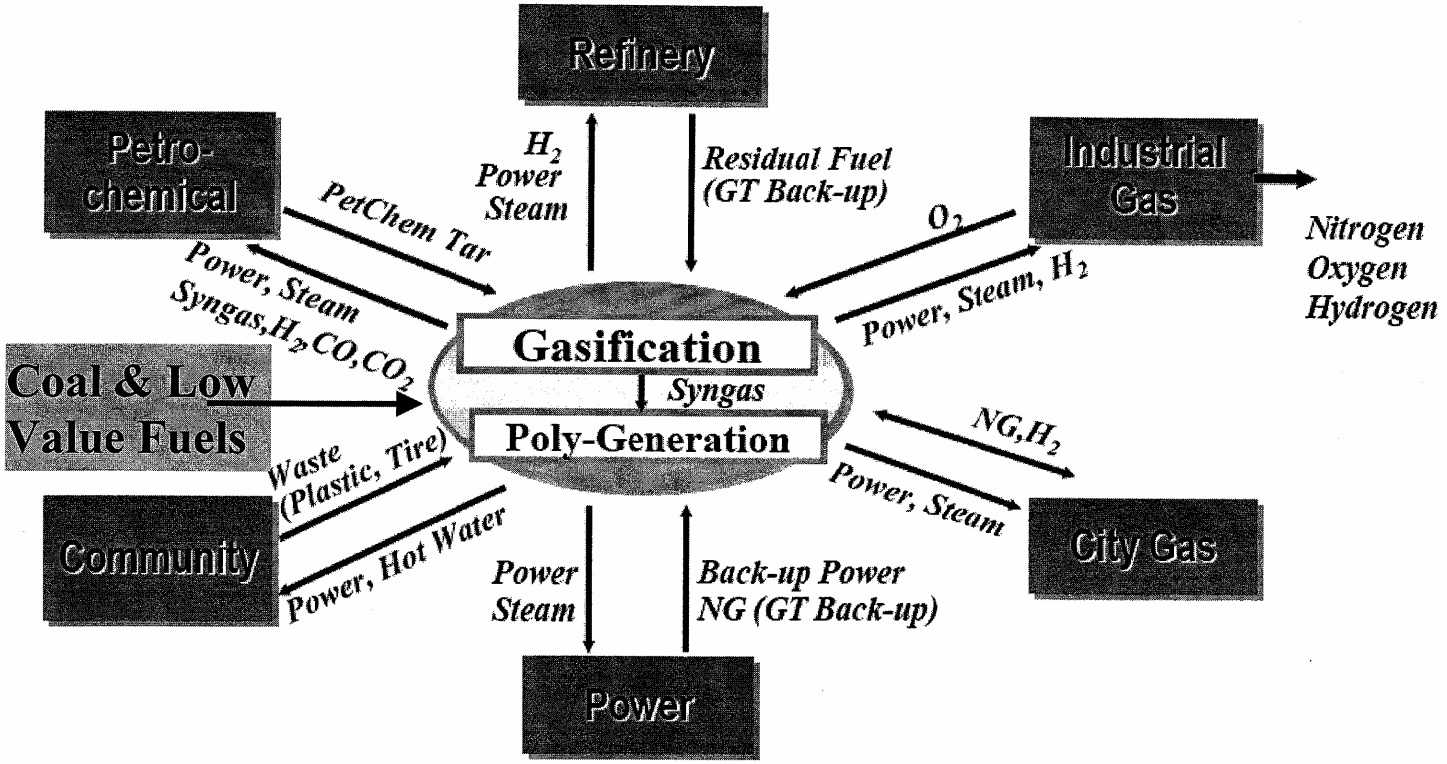
Example of Gasification as a Platform Technology (P.T.)



Polygeneration Opportunities



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H_2 Use in Alberta

- On a per capita basis Canada is one of the largest producers and consumers of hydrogen in the world - about 1.75 million tonnes per year
- Over 70% of this production is in Alberta
  - About 750,000 tonnes of the Alberta production is used in for Upgrading & Refining of oil
- Over 100,000 t/yr is used as fuel by in petrochemical plants

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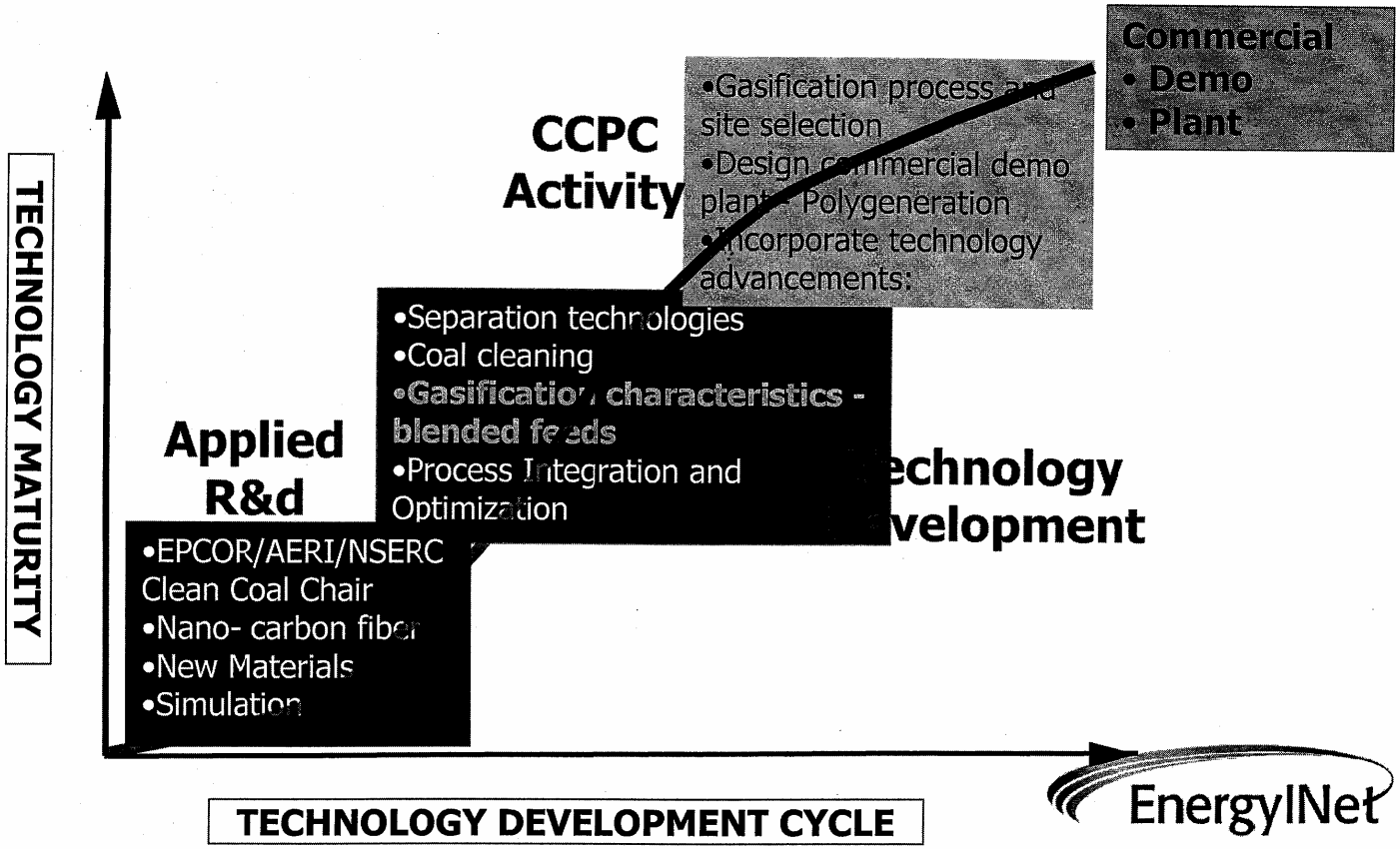
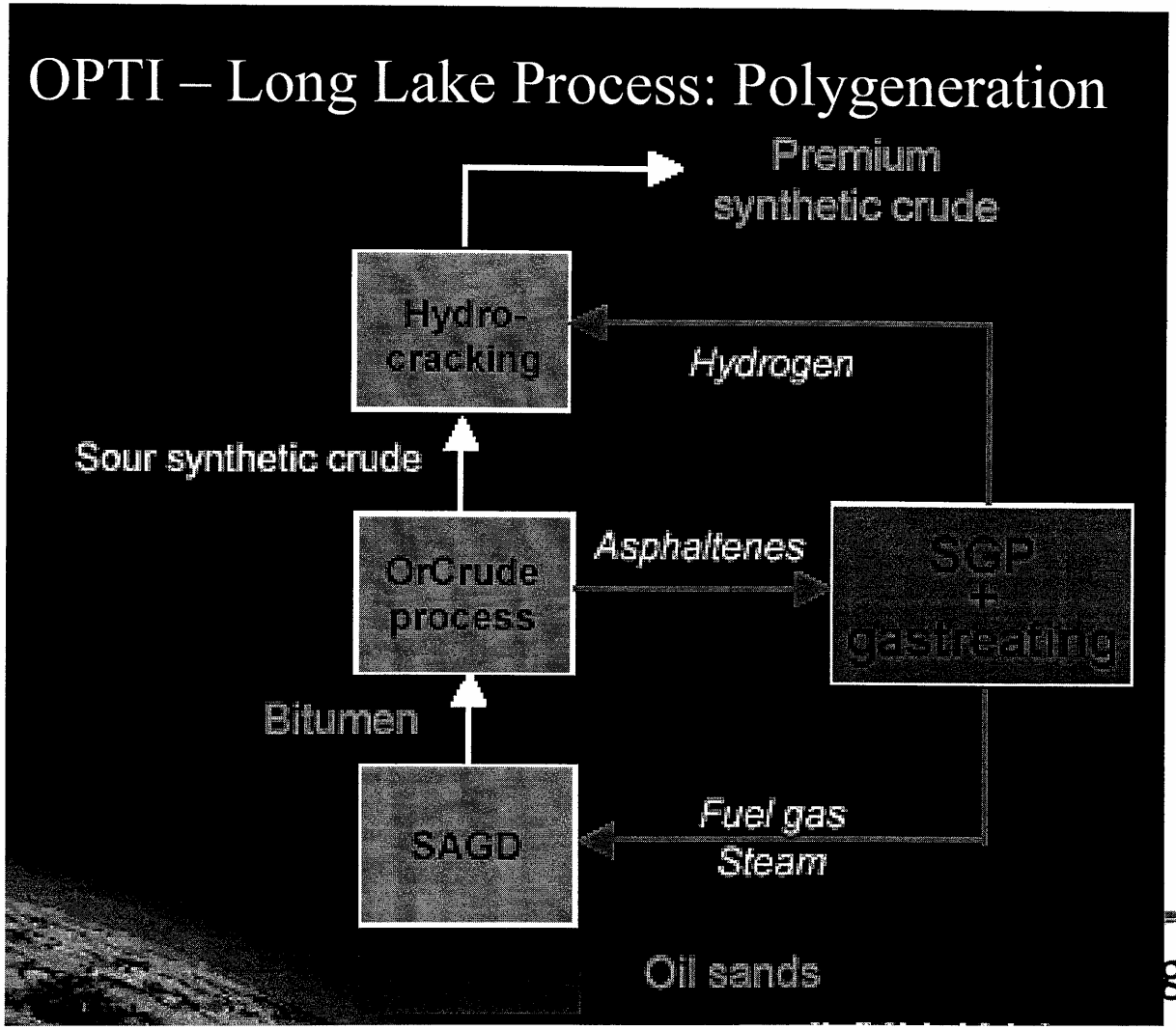
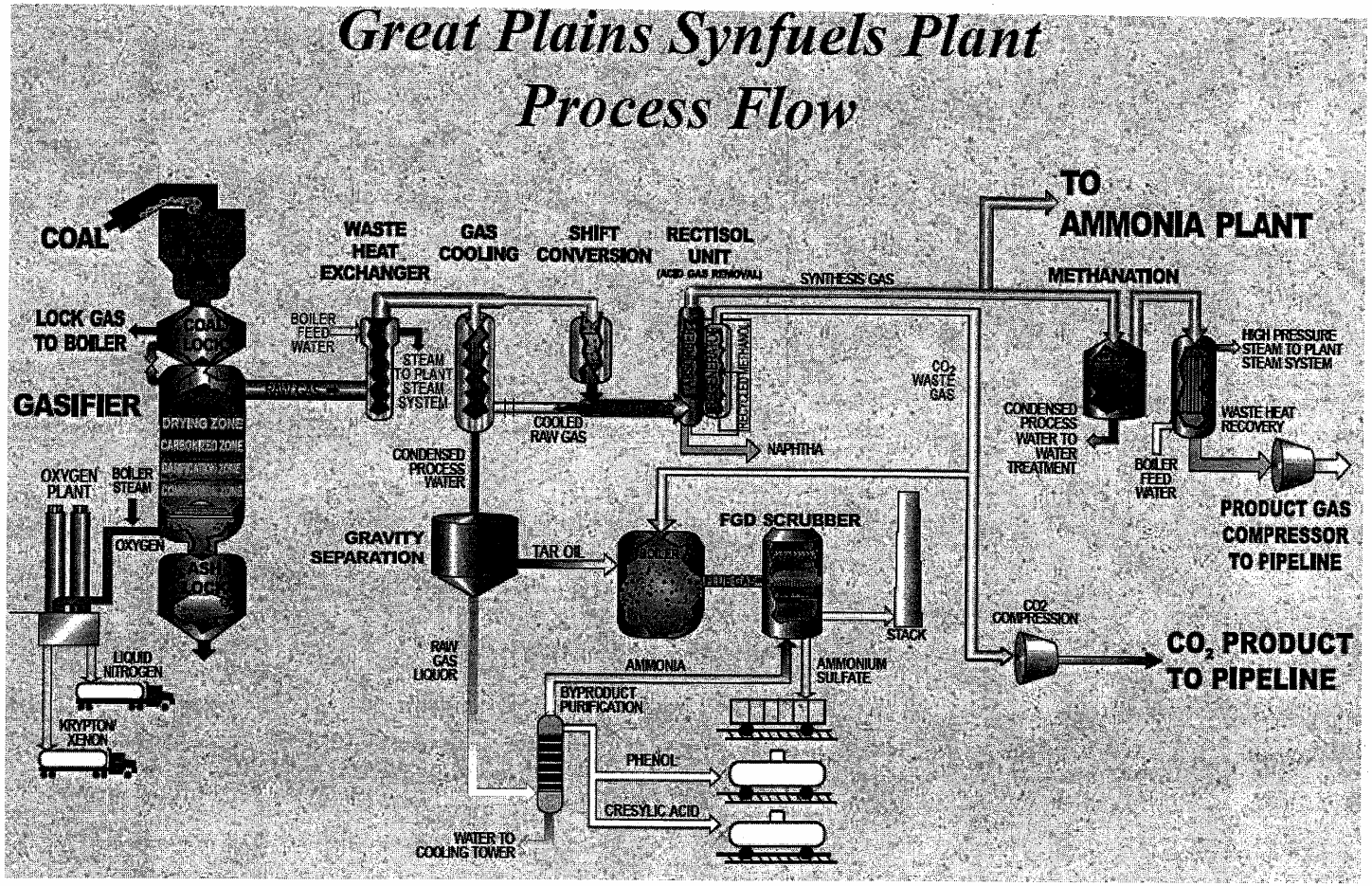
EnergyINet Clean Carbon/Coal Innovation program - Portfolio Balance




OPTI – Long Lake Process: Polygeneration
Premium synthetic crude
Hydro-cracking
Hydrogen
Sour synthetic crude
OrCrude process
Asphaltenes
SGP + gastreating
Bitumen
SAGD
Fuel gas
Steam
Oil sands


Great Plains Synfuels Plant
Process Flow
COAL
LOCK GAS TO BOILER
GASIFIER
COAL LOCK
DRYING ZONE
CARBONIZED ZONE
GASIFICATION ZONE
COMBUSTION ZONE
ASH LOCK
OXYGEN PLANT
BOILER STEAM
OXYGEN
LIQUID NITROGEN
KRYPTON XENON
WASTE HEAT EXCHANGER
GAS COOLING
SHIFT CONVERSION
RECTISOL UNIT
(ACID GAS REMOVAL)
SYNTHESS GAS
TO AMMONIA PLANT
METHANATION
BOILER FEED WATER
STEAM TO PLANT STEAM SYSTEM
RAW GAS
COOLED RAW GAS
CONDENSED PROCESS WATER
RECYCLED METHANOL
NAPHTHA
CO2 WASTE GAS
HIGH PRESSURE STEAM TO PLANT STEAM SYSTEM
CONDENSED PROCESS WATER TO WATER TREATMENT
WASTE HEAT RECOVERY
BOILER FEED WATER
PRODUCT GAS COMPRESSOR TO PIPELINE
GRAVITY SEPARATION
TAR OIL
BOILER
FLUE GAS
FGD SCRUBBER
STACK
CO2 COMPRESSION
CO2 PRODUCT TO PIPELINE
RAW GAS LIQUOR
AMMONIA
AMMONIUM SULFATE
BYPRODUCT PURIFICATION
PHENOL
CRESYLIC ACID
WATER TO COOLING TOWER

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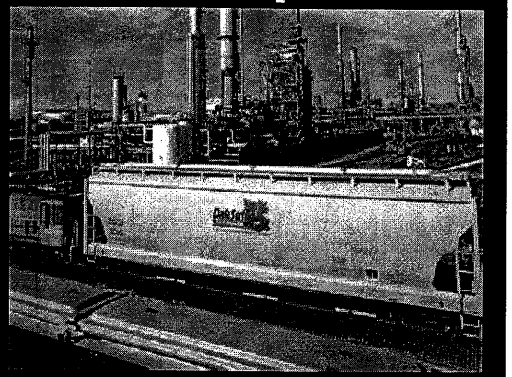
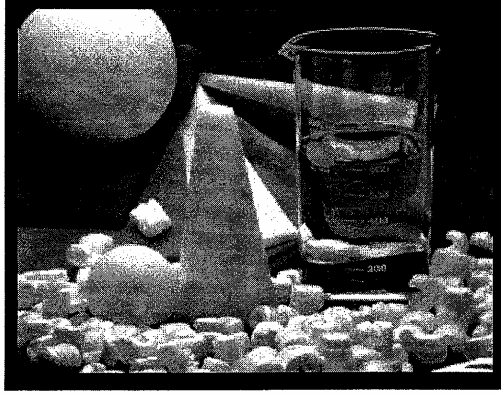
Ammonia
1150 tpd

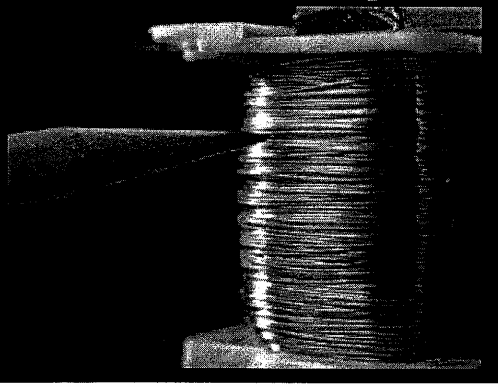
Ammonium Sulfate
575 tpd



Phenol
33 million lb/yr



Cresylic Acid
33 million lb/yr



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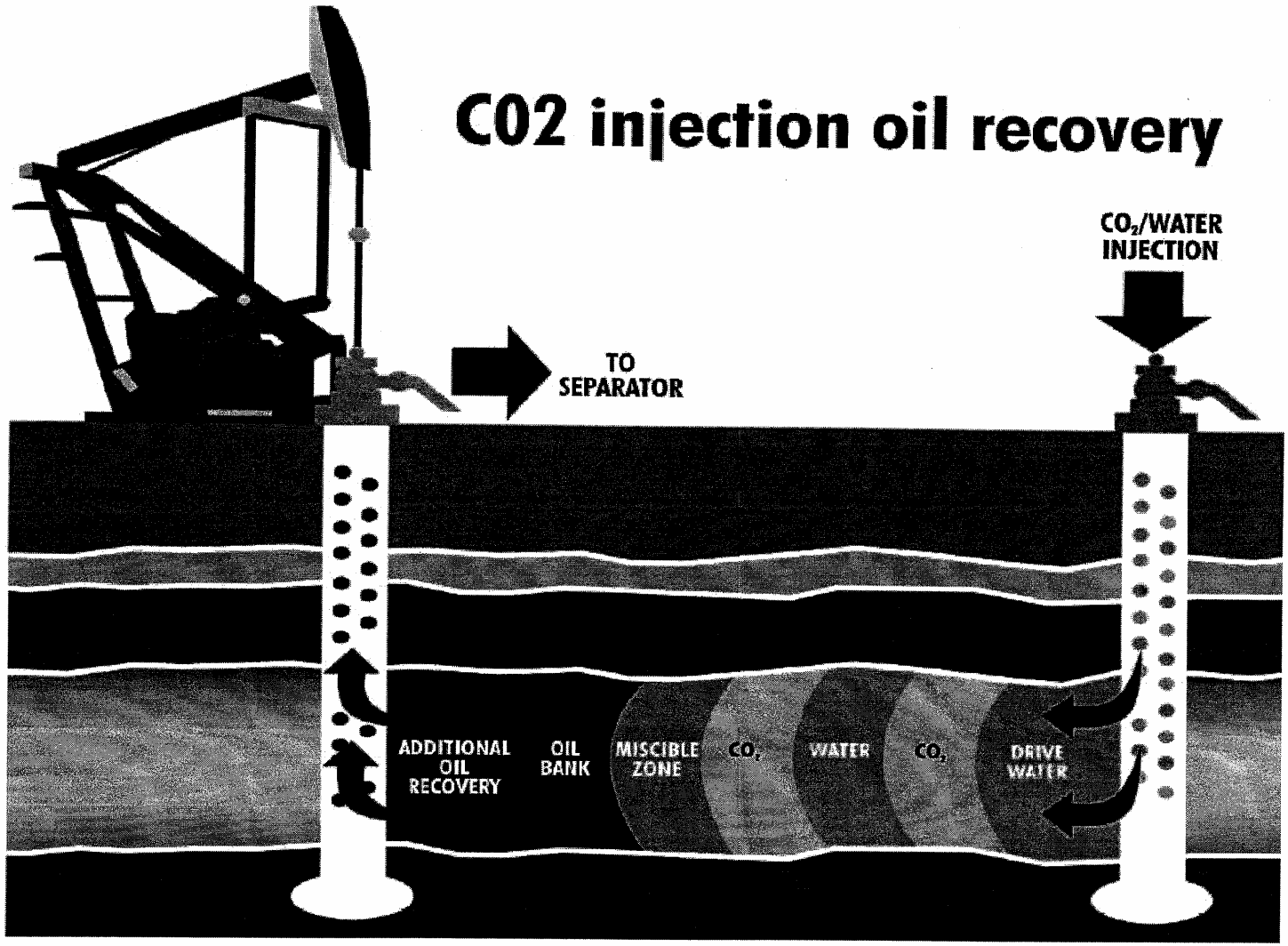
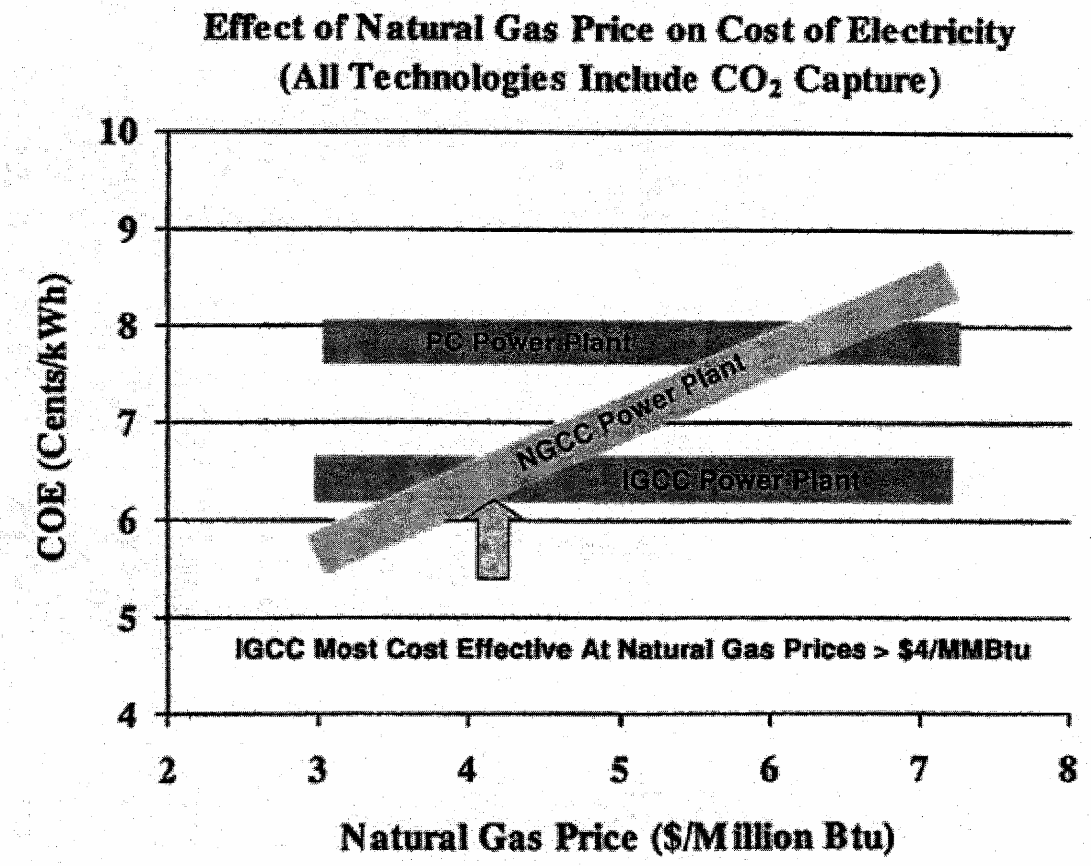

C02 injection oil recovery
CO_2/WATER INJECTION
TO SEPARATOR
ADDITIONAL OIL RECOVERY
OIL BANK
MISCIBLE ZONE
CO_2
WATER
CO_2
DRIVE WATER


Effect of Natural Gas Price on Cost of Electricity
(All Technologies Include CO_2 Capture)
COE (Cents/kWh)
10
9
8
7
6
5
4
PC Power Plant
NGCC Power Plant
IGCC Power Plant
IGCC Most Cost Effective At Natural Gas Prices > $4/MMBtu
2
3
4
5
6
7
8
Natural Gas Price ($/Million Btu)

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AERI/EnergyINET Projects

Project	Industry Partners
Gasification of Low Rank Coals with CO2 capture	Canadian Clean Power Coalition
Coal Cleaning for improved combustion and gasification	Luscar
Gasification of Western Canadian Feeds	Sherritt
Gasification of Municipal Solid Waste	City of Edmonton
Precombustion Coal Cleaning & Mercury Removal	EPCOR/AERI/NSERC Chair at U of A

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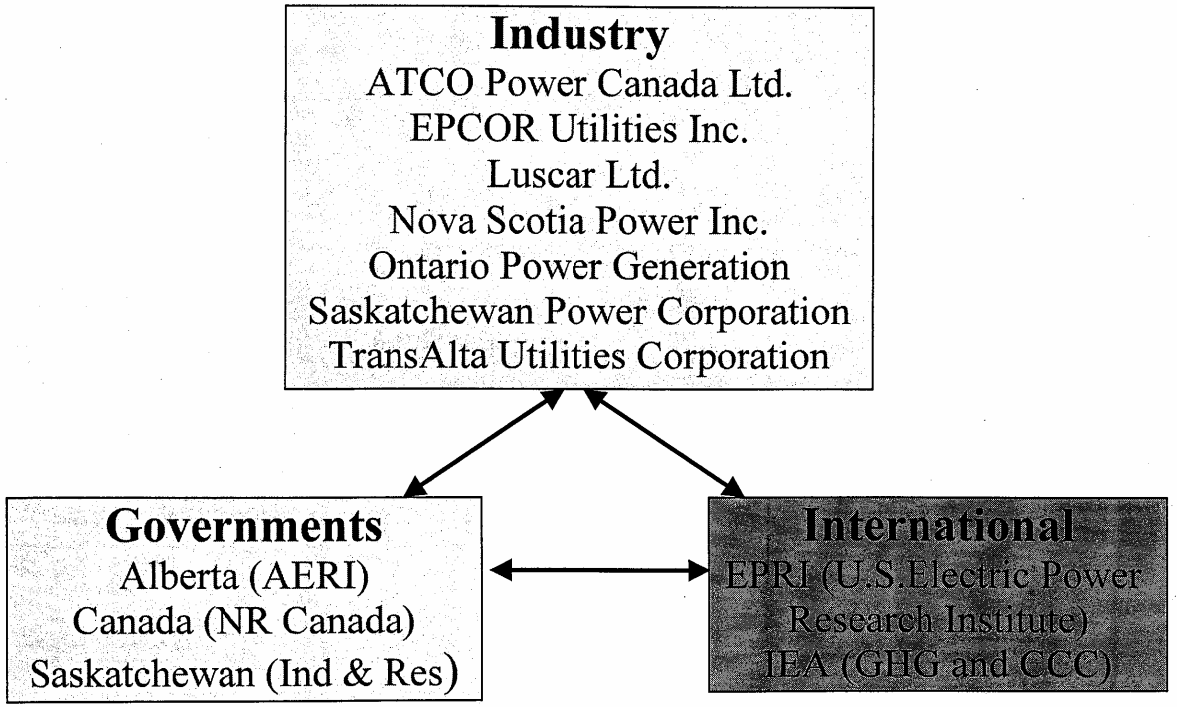
Canadian Clean Power Coalition Partners



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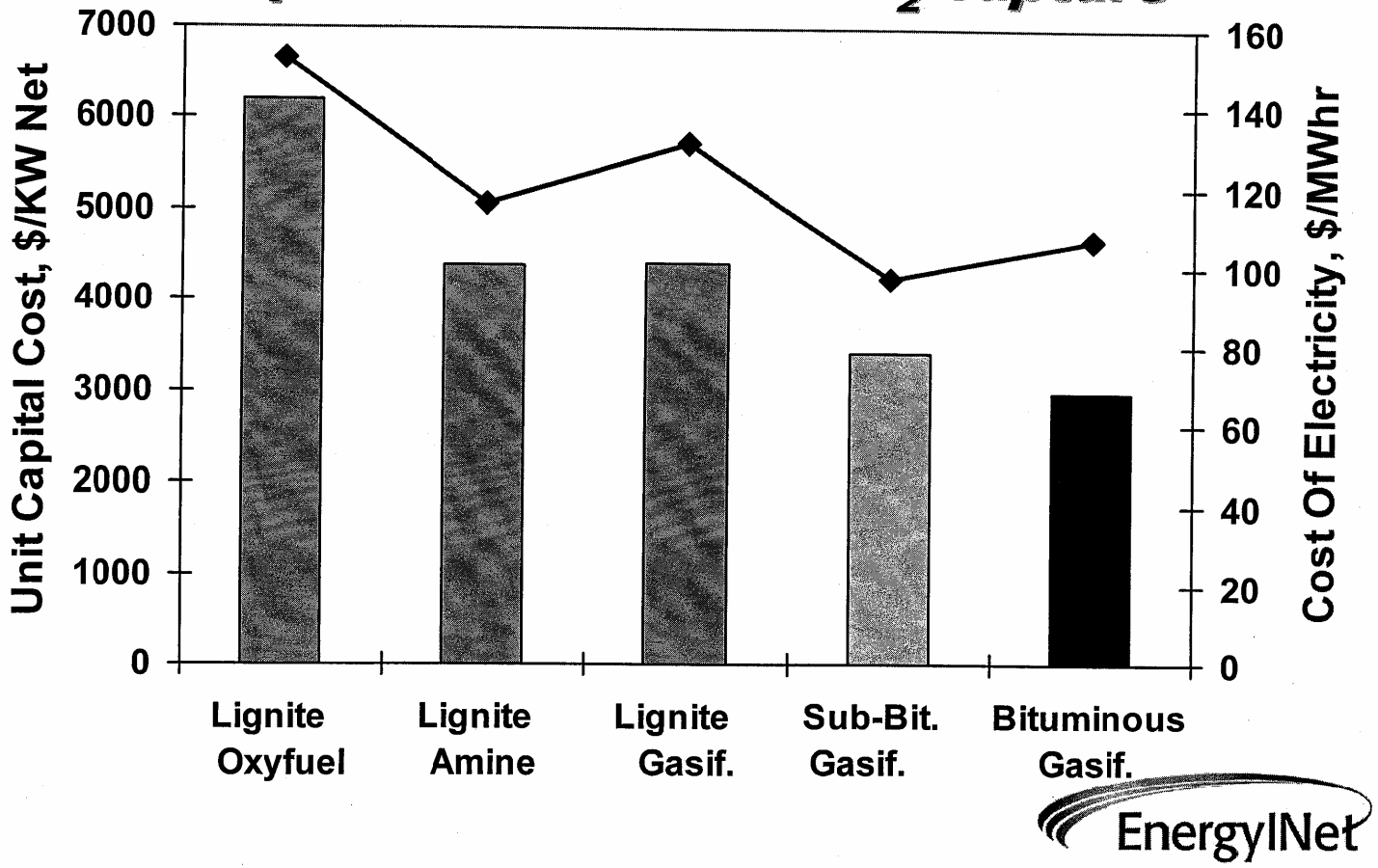
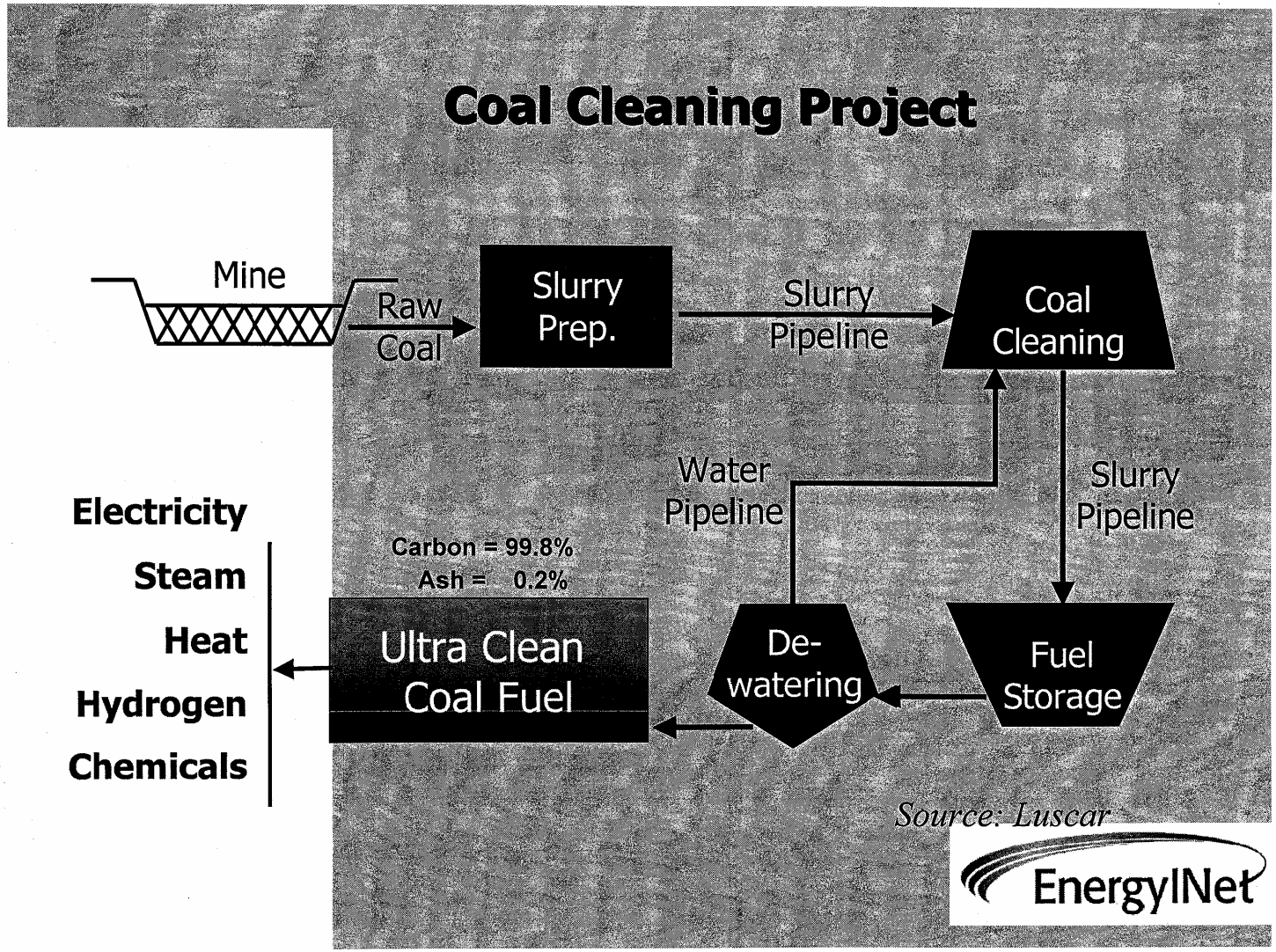
Unit Capital Cost & Cost of Electricity Comparisons for 90 % CO_2 Capture




Coal Cleaning Project
Mine
Raw Coal
Slurry Prep.
Slurry Pipeline
Coal Cleaning
Water Pipeline
Slurry Pipeline
Electricity
Steam
Heat
Hydrogen
Chemicals
Carbon = 99.8%
Ash = 0.2%
Ultra Clean Coal Fuel
De-watering
Fuel Storage
Source: Luscar
EnergyINet

Gasification Feedstock Evaluation & Testing Project

Feedstock	Type
Coals	Subbituminous Coal
	Lignite
	Beneficiated coals
Oil Sands Residues	Delayed coke
	Fluid Coke
	Petroleum Coke
	Asphaltenes
Blended Feeds	Coal/Coke mixtures

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Conclusions

- Gasification/polygeneration converts low value coal and other carbon-based feeds into high value clean energy products: electricity, heat, hydrogen, transportation fuels & chemicals
- Many existing opportunities to replace natural gas in the oils sands and chemical industries
- Next likely applications are in clean power combined with heat and hydrogen generation
- Economic gasification of low rank coals requires technology enhancements and innovation
- AERI/INet/Industry programs are focusing overcoming technical risks and building user confidence

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Sir/Madame,

I am writing with respect to the development of Ontario's future electricity supply mix.

I recommend that the Ontario Power Authority adopt a future power scenario for Ontario that includes a minimum of 60% renewable electricity by 2020 and a full phase-out of power generation from coal. If implemented, these measures (coupled with serious conservation measures) would improve air quality in this province, and they would also represent a serious step toward reducing our emissions of carbon into the atmosphere.

Sincerely,
James Schaefer

I am writing in regards to the future plans of power in Ontario. I am in support of the full phase out of coal and nuclear power, therefore leaving the option of renewable electricity.

Shannon, Garvan, Desmond & Jon

August 15, 2005

To the Ontario Power Authority

Ground-breaking research conducted by the Pembina Institute indicates that it is quite possible for Ontario to get 60% of its electricity from renewable sources by 2020 while eliminating dirty coal and nuclear power.

In our home, my wife and I have succeeded in achieving this goal, and are very close to getting 100% of our electricity requirements from renewable sources.*

For these reasons, we feel that it is very important that you include, in your detailed analyses for our government, a scenario which has heavy emphasis on conservation and renewable energy.

Of course, we also believe that the daily releases of radiation from the mining of uranium through to the storage of radioactive waste fuel from the power plants are a long term, unacceptable pollution of our environment which is just as serious as the damage from coal-fired generation.

*We are a retired couple with a gross family income of under $60,000. This income relies heavily on our pensions, RRIF's, and savings, with no money from stocks, bonds or mutual funds. We regard ourselves as a typical middle class family with many modern appliances, except that we have solar PV panels, solar thermal panels, and a wind generator. We buy only 5.5 Kwh per day from Hydro One.

It is possible to have 60 % of Ontario's electricity coming from renewable sources of energy - no coal, no nuclear.

Yours sincerely, William L. Shore, Edith B. Shore

As much renewable energy supply as possible, please. (Coal is, of course, being phased out and nuclear should only be considered as an interim measure.)

Nan Shuttleworth

advocates for the environment

SIERRA LEGAL DEFENCE FUND

August 26, 2005

Mr. Jan Carr
Chief Executive Officer
Ontario Power Authority
175 Bloor St. E., North Tower, Suite 606
Toronto, Ont. M4W 3R8

Sent electronically to: supplymixsubmissions@powerauthority.on.ca

Dear Mr. Carr:

Re: Building a sustainable, safe, reliable, and clean energy future for Ontario
Comments on Ontario's Proposed Energy Supply Mix

Ontario stands today at a historic crossroad. On one side lies the vast and untapped potential of conservation and renewable power; on the other, a repetition of our unfortunate nuclear and coal-fired power mistakes.

Sierra Legal Defence Fund is Canada's national environmental law organization. Our work is focused on strengthening and enforcing our nation's environmental laws. In the area of energy law, our organization has been closely involved in the fight against coal-fired power in Ontario and the U.S., in reviewing and commenting on Bill 100, which ultimately became Ontario's new electricity act, and in advocating for stronger conservation and renewable energy measures. We also coordinate our efforts with a number of non-profit groups on issues of energy policy and air pollution.

30 St. Patrick Street
Suite 900
Toronto, ON
Canada M5T 3A3

Phone:
416.368.7533

Fax:
416.363.2746

E-mail:
sldfon@sierralegal.org

Website:
www.sierralegal.org

We urge you to take Ontario on the road of an aggressive conservation strategy with wiser energy use achieved through strong planning and implementation while harnessing the many exciting renewable power options (wind, solar, cogeneration, biomass, geothermal). We believe that this road offers cost-effective, sustainable, and prudent energy choices for Ontario.

Ontario's Minister of Energy recently stated his intention to create "…a clean, reliable, diverse and sustainable supply of energy" for the province. We believe that his statement gives us a common cause.

The Minister has also repeated his commitment to phase out Ontario's dirty coal-fired generating stations. We laud his government for this commitment, providing the underlying decisions on how to replace this power are made in a timely way and are consistent with a sustainable and clean power future. We also applaud the recent government announcement to follow the successful European example of allowing small producers to participate in the energy supply market with Standard Offer Contracts that guarantee prices for fixed terms. These are important first steps.

We are disheartened, however, by the Ontario government's recent public musings about additional nuclear power plants. Replacing coal-fired power with nuclear power simply replaces one set of problems with another. Indeed the current dilemma with replacing the dirty power produced by coal is strongly related to the closure of certain nuclear facilities --- precipitated by safety concerns --- in the 1990s. These closures resulted in the expansion of coal-fired power. Today the proposed solution to coal-fired power is expansion of the province's nuclear capacity. Hopefully the irony of this "solution" is evident. Surely Ontario does not need to be kept on such an unfortunate cycle.

The reports of numerous government and non-government organizations have documented the alternative path provided by the untapped potential of conservation and renewable power. Several years ago, the government's own multi-party S*elect Committee on Alternative Fuels* concluded that aggressive action on alternative fuels and energy could serve to substantially reduce Ontario's dependence upon traditional petroleum-based fuel and energy sources. In making this conclusion, the Committee recommended that Ontario utilize untapped water, wind, biomass, and solar power (among others) in the province to reduce this dependence.

The Select Committee recognized the potential in:

- expediting the utilization of wind power in Ontario;
- collecting and using fuel gases from landfill, agricultural, and forestry operations;
- using solar power for heating applications and electricity generation; and
- refurbishing existing hydraulic facilities and establishing new hydraulic sites across the province.

More recently a comprehensive report by the Pembina Institute in conjunction with the Canadian Environmental Law Association (CELA) found that the energy needs (demands) of the province could be met by investments in technologies and infrastructure that utilize Ontario's:

- onshore wind power capacity, which ranges between 2,000 and 7,500MW;
- biomass (landfill and waste digestion generated gas combustion) capacity of 800MW; and
- waterpower potential providing an output capacity between 1,200 and 4000MW;

The Pembina/CELA report also outlined the province's 14,000 MW potential by 2020 from reducing the demand for electricity through energy efficiency, fuel switching, cogeneration, demand response measures, and on site generation. The investment in Ontario's water potential, biomass resources, and wind power capacity could lead to a contribution to the energy supply by 2020 of 32,762 GWh.

Another significant report by the *David Suzuki Foundation* showed that energy efficiency and conservation strategies are the most logical complement to the widespread use of renewable energy sources, and in particular that Ontario could install:

- Up to 8,000MW of wind generating capacity by 2012 (10% of current capacity), supplemented by a portion of existing hydroelectric power with water reservoir capacity in periods of low wind availability;
- 1,000MW by refurbishing small scale and low impact hydroelectric sites;
- 2,450MW of power generation using a variety of biomass sources, 426MW by 2007;

- 1,263MW worth of photovoltaic systems; 800,000 solar domestic hot water systems; 120,000 solar pool heaters; solar passive design in 420,000 new homes; 2,000,000m^2 of commercial and institutional solar hot water systems; and 825,000m^2 solar air ventilation systems (similar to coal power or half the electricity generated by nuclear power plants); and
- Geothermal pumps which could save the equivalent of 2,148,000MWh per year

Other jurisdictions have already succeeded in putting themselves on the path to a cleaner, more sustainable energy future. Germany, for instance, installs more wind power annually than Ontario's current target for all renewable energy sources. This summer Quebec has committed to doubling its target for wind power. Ontario's potential is even greater.

Yet, despite these documented opportunities and despite the enlightened words of the Minister, the government appears intent on continuing to press the same buttons --- particularly nuclear power --- that have a proven history of failure. The problems with nuclear are certainly well-known:

- The prohibitive cost and the legacy of public debt in Ontario;
- The record of poor reliability and performance;
- The massive and often unaccounted for decommissioning costs;
- The enormous security risks and costs;
- The small but real risk of a catastrophic accident;
- The routine and accidental emissions of radioactive substances from Ontario's reactors;
- The poor environmental legacy of uranium mining in Canada and outstanding site remediations; and
- The safe management of radioactive wastes for up to a million years.

We are also concerned that the limited government funds available for energy investment will mean that nuclear spending will come at the expense of the more prudent options provided by renewables and conservation. Similarly, we are concerned about the refurbishment of reactors at various existing sites, although the very recent decision not to refurbish Units 2 and 3 at Pickering A is encouraging. Extending the life of Ontario's oldest reactors simply perpetuates the societal risks of nuclear power. We also fear that further investment in nuclear will simply put off for another generation real solutions --- ones that are truly sustainable, secure, and wise. Why squander such an opportunity?

A decision to invest in nuclear power not only commits Ontario to the spending entailed by construction but also to the massive costs of decommissioning, unknown security risks, and liability issues. In other words, once this road is taken the passengers --- namely Ontarians --- end up on a trip from which it is difficult to escape. As well, if the U.S were to follow an aggressive nuclear program, Ontarians would be very uneasy about seeing dozens of new nuclear plants facing them from across the Great Lakes.

Although we understand the suggestions of nuclear advocates that past political and other mistakes that exacerbated the cost of nuclear will not be repeated, the fact is that mega-projects present the possibility of mega-mistakes. Indeed, such mega projects hardly fit in with the government's vision of a reliable and diverse supply given the massive public funds that are again being siphoned into one single source, namely, nuclear power. The Minister himself has indicated his own reservations in his May 5th Empire Club speech, saying "[t]he

first 40 years in Ontario's nuclear experiment has had significant cost over-runs, inefficiencies and breakdowns that we cannot and should not ignore." We agree.

A future based on conservation and renewable energy has its own risks but they are the diversified risks of many smaller projects and initiatives. It will certainly take ingenuity, courage, and leadership to craft and commit to the multi-faceted policies and initiatives that will be needed to build a diversified, secure, and sustainable energy future but we believe our province is up to the task.

We would be pleased to meet with you directly to discuss our green energy vision for Ontario.

Sincerely,

_____

Albert Koehl
Staff Lawyer

SIERRA LEGAL DEFENCE FUND

cc. The Hon Dwight Duncan, Minister of Energy

I agree that OPA should include a scenario with a minimum of 60% renewable electricity by 2020, as per the Ontario Clean Air Alliance recommendation below.

Thank you,

Mark Singh

Social Housing Sectoral Conservation and Demand Management Strategy

Social Housing Services Corporation

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TABLE OF CONTENTS

EXECUTIVE SUMMARY	3
INTRODUCTION	5
SHSC	6
ENERGY MANAGEMENT PILOT PROJECT	7
PLAN BUDGET AND ASSUMPTIONS	8
OBJECTIVES	9
CRITERIA	9
SECTORAL CONSERVATION AND DEMAND MANAGEMENT STRATEGY	10
ENERGY EFFICIENT RETROFITS/RENEWABLES	11
RESIDENT ENERGY AWARENESS AND PRACTICES	17
ENERGY EFFICIENT NEW CONSTRUCTION	19
CONCLUSION	20
CONTACT INFORMATION	20
PROGRAM BUDGET AND TIMELINE SUMMARY	21

Executive Summary

- Ontario is facing serious challenges in meeting its future electricity needs.

- SHSC's CDM Strategy is designed to alleviate energy poverty among low-income Ontarians, and to manage energy demand from a sectoral approach, for existing and new social housing across Ontario.

- Five Criteria:

  A. Sectoral Benefits – Distribute benefits broadly to the social housing sector across Ontario, including remote/aboriginal communities.

  B. Innovative Measures – Implement innovative technology and approaches where feasible.

  C. Achieving Targeted Results – Preference is given to implementing measures that offer more predictable results.

  D. Leveraging Partnerships – Public resources to leverage private sector investment and strategic alliances for mutual and ongoing benefits.

  E. Economic Development – Utilize economies of scale to spur economic development and market transformation in key energy-related industrial sectors in Ontario.

- Recommended Strategies:

  Strategy 1:

  Energy Efficient Retrofit/Renewables

  Measure 1 – Replace existing refrigerators with 100,000 Energy Star models over 10 years.
  Measure 2 – Install 10,000 m² in collector panels for Solar Hot Water Heating Systems over 10 years.
  Measure 3 – Replace existing toilets with 100,000 Low-flow Toilets over 10 years.
  Measure 4 – Replace existing lighting with 500,000 Compact Fluorescent Lights over 5 years.
  Measure 5 – Help develop innovative lighting and renewable energy products to achieve market readiness over 3 years.

Strategy 2:

Resident Energy Awareness and Practices
Full-menu resident engagement initiatives for 200 buildings over 5 years.

Strategy 3:

Energy Efficient New Construction Investment

Measure 1 – Establish energy efficient design standards, including deployment of renewable energy applications, for new construction in social housing.

Measure 2 – Establish a multi-year funding program providing upfront incentives and financing for zero-interest loans to energy efficient new social housing construction.

Introduction

Under the *Electricity Act,* the Minister of Energy may issue directives with respect to the overall goals of the Ontario Power Authority's long-term power system planning. Before issuing such directives, the Minister has requested advice from the Ontario Power Authority (OPA) on the future "supply mix" for Ontario. The OPA is required to deliver this advice by December 1, 2005.

The Minister's request of the OPA on "supply mix" specifically includes:

- Recommendations with respect to conservation targets for Ontario for 2015, 2020 and 2025, taking into account the target already set by the Government of Ontario for 2007;
- Recommendations with respect to additions of new renewable energy capacity by 2015, 2020 and 2025, taking into account the targets already set by the Government of Ontario for 2007 and 2010; and
- Recommendations with respect to the appropriate mix of electricity supply sources to satisfy the remaining expected demand in Ontario, after conservation and renewable sources have been taken into account, and with particular attention to baseload, intermediate and peak availability of energy.

In order to advise the Minister, the OPA sought stakeholders' input on four issues areas, including:

> Appropriate approaches to constructing CDM ("Conservation and Demand Management") portfolios for inclusion in long-term plans. These approaches will be of the greatest value where they include established data on technical and achievable potential, costs, implementation barriers, sector specific characteristics, experience in implementation of CDM, and technology developments.

Social Housing Services Corporation makes this submission to the OPA, outlining our experience in energy conservation, and our proposal for a province-wide Conservation and Demand Management Strategy for the social housing sector across Ontario.

Social Housing Services Corporation

Social Housing Services Corporation (SHSC) was established under the provisions of the *Social Housing Reform Act, 2000.* The *Act* provided the legislative authority to devolve social housing to municipal Service Managers by June 2002. The *Act* also established SHSC as an independent corporation representing the interests of its members consisting of municipal Service Managers, Local Housing Corporations, non-profit and co-operative Housing Providers previously administered by the provincial government.

SHSC is governed by a fifteen-member Board of Directors, two of whom are appointed by the Province of Ontario, with the balance from its membership, including municipal representatives from Algoma District, Burlington, Haldimand, Grey, Ottawa, Peel, Prince Edward-Lennox-Addington and Toronto.

The establishment of the SHSC essentially fulfills the need for a central body to serve as a resource to 47 Service Managers and 1,600 Housing Providers in 455 municipalities and districts who collectively manage 250,000 social housing units in Ontario. In addition to representing its members in matters related to existing social housing units, the SHSC is also directed to represent our members in the construction and administration of new housing units, including those created under the new Affordable Housing Program.

SHSC fulfills the need for consistent quality and to facilitate services to Housing Providers across the province, while taking advantage of economies of scale. The objective of establishing SHSC, with a province-wide role, was to provide:

- management of insurance programs with $15 million in annual premiums;
- pooling of capital reserve funds of approximately $300 million;
- joint purchasing of goods and services, including $34 million annual natural gas purchase program; and,
- the provision of research information and advice to the Province, Service Managers and prescribed Housing Providers with respect to the establishment of benchmarks and best practices to achieve the efficient and effective provision of housing.

Social housing units were transferred from the provincial government to municipal Service Managers between January 2001 and May 2002. During this time, SHSC developed its organization and established support systems for its members. It has become apparent that many of the member Service Managers and Housing Providers need support for a wide range of business and housing support services, including energy management services.

SHSC is undertaking an Energy Management Pilot Project on behalf of its members across the province, by developing a comprehensive approach to energy conservation and creating a framework from which providers and service managers can draw upon the expertise, resources and economies of scale to implement energy conservation initiatives.

Energy Management Pilot Project

SHSC has launched a pilot project with approximately 40 Housing Providers in twenty communities across Ontario including Guelph, Haliburton, Hamilton, Iroquois Falls, Kingston, Kitchener, Milton, Mississauga, Newmarket, North Bay, Oshawa, Ottawa, Peterborough, Richmond Hill, Sudbury, Toronto, Waterdown, Wawa, Whitby and Windsor. In total 50 buildings and with 4,300 housing units in co-ops, non-profits, and Local Housing Corporations (LHCs) participated in the project. The pilot aims at assessing the effectiveness of the mechanisms and processes for larger deployment. These various processes include conducting energy audit, funding, implementation and ongoing measurement of energy efficiency and conservation retrofits.

An invitational Request for Proposals was issued to select energy auditors capable of auditing the wide range (location as well as type) of buildings in the province. SHSC selected nine firms to perform energy audits. These audits were completed in the summer of 2005 and will lead, pending a decision by each provider's board, to various retrofits based on the conclusions of the audit report.

At this stage, Housing Providers will have to prepare their business case for moving forward with the retrofits or changes as proposed by the auditors. The next stage involves connecting providers with the requisite funding sources and assisting them in procuring services through which they can implement their energy conservation strategies.

SHSC's goal is to create a social housing focus with funders and utilities and to identify grant and incentive opportunities, while streamlining the application processes. Working with the Ontario Ministry of Energy, SHSC has put forward a funding application under the Federal-Provincial Opportunities Envelope program. We have applied to the Green Municipal Funds, a funding program of the Federation of Canadian Municipalities. To kick-start our pilot, we have been successful in sourcing funding from Canada Mortgage and Housing Corporation (CMHC), several Local Distribution Companies and both gas utilities.

SHSC has also developed a low-cost lending vehicle, which will enable Housing Providers to access capital to fund the elements of the retrofit that are not covered by grant or incentive funds, or not paid for out of capital reserves.

The Pilot Project established actual and more detailed baseline measurements for 4,300 social housing units. The energy pilot retrofit implementation will reduce energy consumption by an estimated 2,500,000 kWh of electricity and 700,000 m^3 of natural gas, which translates into 3,500 tonnes in Greenhouse Gas reduction.

SHSC recommends building on the Energy Management Pilot Project, to implement a province-wide Conservation and Demand Management Strategy for the social housing sector across Ontario.

Strategy Budget and Assumptions

SHSC is proposing a comprehensive, province-wide, multi-year Conservation and Demand Management Strategy for the social housing sector in Ontario. Our CDM Strategy will provide aggregated demand reductions for this important public sector.

Under a contractual agreement with the OPA, SHSC will manage a sectoral CDM Fund that supports program design, energy capital improvements, monitors progress and reports to the OPA annually on achieved demand reductions.

The Social Housing CDM Fund will consist of investments from both public and private sectors, including venture capital and pension funds. The OPA will help identify and access public sector funding, including but not limited to, any federal and/or provincial funds supporting energy retrofit for social housing, and for construction of new affordable housing.

The total budget is $125 million over 10 years, with 70% towards energy retrofits and resident awareness and practices, and 30% towards energy efficient new construction. Public sector investments will be used to leverage further investment from the private sector. SHSC is proposing an investment of public funds in the amount of $125 million.

SHSC's sectoral CDM Strategy is therefore based on investing annually approximately $12.5 million on average in a combination of capital and operating expenses during the 10-year period from 2006 to 2016. The proposed CDM Fund requires an initial five-year commitment, renewable for another five years.

While the current strategy is well balanced, it is recognized that the industry and regulatory framework is dynamic. SHSC will continue to assess and update its strategy as new opportunities are presented. If necessary, SHSC will re-allocate funds between programs to respond to demand levels expressed by Housing Providers and Service Managers.

Objectives

The Province of Ontario is facing serious challenges in meeting its future electricity needs. Energy conservation and demand management has been identified as one of the most viable and cost-effective means of meeting the province's energy needs in the short term.

The Minister of Energy has called for the creation of a 'Conservation Culture' in the province, and has established two important objectives for the electricity sector and electricity consumers, including a reduction in Ontario's demand for electricity by 5% by 2007, and the full deployment of SMART meters for all electricity consumers by 2010.

The objective of SHSC's CDM Strategy is to contribute to the emergence of a conservation culture in Ontario, to alleviate energy poverty among low-income Ontarians, and more specifically, to support the Minister's commitments to manage energy demand from a sectoral approach, for existing and new social housing across Ontario.

Criteria

In developing this strategy, the following criteria were used to guide the selection of component programs:

A. Sectoral Benefits – The overall strategy should distribute benefits broadly to the social housing sector across Ontario, including remote/aboriginal communities.

B. Innovative Measures – Implement innovative technology and approaches where feasible.

C. Achieving Targeted Results – Preference is given to implementing measures that offer more predictable results.

D. Leveraging Partnerships – Public resources to leverage private sector investment and strategic alliances for mutual and ongoing benefits.

E. Economic Development – Utilize economies of scale to spur economic development and market transformation in key energy-related industrial sectors in Ontario.

Social Housing Sectoral Conservation and Demand Management Strategy

The province-wide social housing sectoral CDM Strategy will reduce electricity consumption by 73.5 million kWh or 315,000 GJ.

SHSC's sectoral CDM Strategy consists of three components: Energy Efficient Retrofits/Renewables, Resident Energy Awareness and Practices, and Energy Efficient New Construction Investment. Taken together, these components are designed to create a Conservation Culture in the social housing sector across Ontario, an ideal expressed by the Minister of Energy, as well as continued federal commitment to energy retrofit and to new affordable housing.

SHSC's energy consumption survey showed that Housing Providers pay 82% of the electricity costs of the social housing units, while residents pay the remaining 18%. For residents who are not responsible for energy costs, many are not aware of the net benefit of energy conservation. While the Minister is committed to the full deployment of SMART meters for all electricity customers by 2010, the conservation efforts amongst social housing residents need to start as soon as possible to maximize reduction in consumption and demand.

This sectoral approach is consistent with SHSC's economies of scale business model, and allows both senior levels of government to focus on savings on the estimated $400 million in utility costs for social housing units, as well as the considerable up-stream savings on energy and water infrastructure costs. The Strategy recommends measures that are pervasive and achievable, but by no means exhaustive. It is meant to provide additional impetus to Housing Providers and to encourage them to continue with other conservation measures as they see fit.

SHSC's sectoral CDM Strategy is a made-in-Ontario solution aimed at integrating the ideals of a Conservation Culture into community energy planning and practice. Our Strategy complements Local Distribution Company's CDM plans that contain low-income components as available and approved by the Ontario Energy Board, as well as current incentive programs available from gas utilities and the federal government.

Strategy 1: Energy Efficient Retrofits/Renewables

Measure 1: Refrigerator Replacement

Refrigerator energy savings are determined by the difference in electricity consumption between the existing unit and the replacement unit. In general, refrigerator electricity consumption is a function of type, size and age of the unit, whether the unit is functioning properly, and the temperature of the space in which it is located. All other factors being equal, older refrigerators use more electricity, with the all-time highest consumption by refrigerators from the late 1970s.

According to federal NRCan information, a top-mounted 16.5 cu. ft. refrigerator manufactured in 1990 consumes 137% more electricity measured by kWh per year, than an Energy Star model manufactured in 2002. Side-by-side models use more electricity than top- or bottom-freezer models, partly because these tend to have features such as through the door water and ice.

Refrigerator replacement offers the most consistent and proven return in energy savings. Depending on the vintage of the refrigerators that are currently in service, these savings could reach substantial levels and provide reliable reductions in energy consumption. This in itself is not an innovative measure but a sure-fire way to maximize impact under a large-scale implementation, as exemplified by the efforts undertaken by the New York Power Authority where 180,000 refrigerators were replaced in New York City's public housing stock.

Out of the 4,300 housing units in our Pilot, our auditors recommended refrigerator replacement for 2,000 of the units. For the entire social housing stock of 250,000 units across Ontario, it is conceivable that up to 100,000 old refrigerators could be replaced with Energy Star products over ten years. This will complement Toronto Community Housing Corporation's multi-year refrigerator replacement project, and provide a significant reduction in energy demand in the Greater Toronto Area, the most constrained region of the provincial energy grid.

SHSC recommends a Refrigerator Replacement Program, as a signature component of our social housing sectoral CDM Strategy, with 10,000 replacements per year for 10 years, saving a total of 53,567,000 kWh, or 192,826 GJ over 10 years. At $400.00 per refrigerator, the yearly costs of up to $4 million could be a part of a social housing sectoral CDM Fund, and/or supplemented by off-balance sheet financing.

With our potential buying power, SHSC could enter into a strategic alliance with a motivated manufacturer, for bulk pricing and potentially for the introduction of a new generation Energy Star product, and/or leverage a refrigerator assembly facility in Ontario. In addition, to ensure that these replaced refrigerators will not get back into the consumer market, 10,000 refrigerators will be recycled per year providing an opportunity for local economic development.

Measure 2: Solar Water Heating System

Solar water heating systems use energy from the sun to heat water. The systems use a heat collector, generally mounted on the roof in a south-facing direction, in which a fluid, such as glycol is heated by the sun. This fluid is used to heat up water that is stored in a hot water tank inside the building. The systems work very successfully in all parts of the world, with over 30 million m² of solar collectors installed, including Australia, China, France, Germany, India, Japan and the U.K. where sunlight conditions are more diffused.

The fluid circulating through the solar collectors heats up as it passes through the tubes inside the collectors and then returns to a heat exchanger and a hot water storage tank. The solar-heated water passes through a heat exchanger and the building's existing boiler unit to reach the preset temperature. Energy saving is achieved through the energy consumption differential of the solar-heated water temperature and the boiler set-point water temperature. Ideally the collectors should be mounted on a south-facing roof, although south-east/south-west will also function successfully, at an angle of between 10 and 60°. The collector panels can be bolted onto a pitched roof or integrated into a flat roof with supports.

Solar water heating systems are suitable for buildings that have sufficient year round hot water needs (ideally during the day) and a suitable south-facing roof of sufficient size. Savings from solar water heating are dependent on how much water residents use and at what times they use it. The system is particularly beneficial for buildings where residents are at home using hot water during the day, for example, young families or seniors.

Solar water heating is a proven renewable energy alternative to burning heating fuel or using electricity. Energy savings can normally reach 40% to 50% in most regions of Canada. Simulation models based on a 6m² application and local weather patterns, reach a consistent 45% energy saving for southern and eastern Ontario and 44% energy saving for Thunder Bay.

Through the Department of Natural Resources (NRCan), the federal government has created the Renewable Energy Deployment Initiatives (REDI) in April 1998. REDI is a 9-year program with funding available till March 2007. To date, REDI has mainly supported market development, industrial infrastructure development and biomass combustion in terms of incentives, in the industrial, commercial, institutional and multi-unit residential sectors, as well as federal facilities. Effective January 2005, REDI has re-focused its incentives for solar water heating and solar air heating, and phased down incentives for biomass combustion, with a total budget for all sectors of $3 million for fiscal year 2005 and $3.1 million for fiscal year 2006.

SHSC's energy retrofit pilot has identified three buildings where solar water heating retrofits are feasible and recommended. The relatively high capital investment prolongs the energy pay back period to a point that may render it unfeasible. SHSC recommends a 10-year social housing sectoral Solar Water Heating System program of $8,000,000 in incentives toward the capital costs to install up to a total of 10,000 m² in solar collector panels. The program will step up from $500,000 in Year One to $1.2 million in Year Ten,

ensuring the domestic solar hot water manufacturers have the capacity to respond to the increasing demands. This sector-specific program does not duplicate NRCan's program and allows REDI to focus on other building types and sectors. Installing Solar Hot Water Systems sector-wide represents 15,890,000 kWh, or 57,199 GJ in energy savings.

Currently, there are between 360-500 solar firms in Canada. The industry employs between 900-1,200 people, producing 2,000 m^2 per year in solar collector panels installed. A protracted 10-year SWH installation plan in the social housing sector across Ontario, including remote and aboriginal communities, will contribute to economic development in Ontario.

Measure 3: Low-flow Toilet Replacement

Water Conservation does not only save a valuable resource, it has profound implications for energy consumption. It requires a tremendous amount of energy to undertake water filtration and treatment in the cycle of water usage. In the U.K. supplying water and treating gray water and sewage uses 220 kWh per year per household, more than 50% of the energy required to operate an Energy Star refrigerator for one year. The City of Toronto uses 535,000,000 kWh annually in water filtration and treatment.

Several municipalities in Ontario have implemented wide-ranging water conservation measures, including the Region of Durham, City of Guelph, City of Toronto and Waterloo Region. These measures are aimed at reducing household consumption by giving out simple and proven devices such as low flow shower-heads, aerators, and toilet bowl dampers. Other effective measures include monetary rebates on implements such as front-load water-efficient washing machines and low-flow toilets.

SHSC recognizes the efforts of these simple measures as every incremental step helps Ontarians towards the ideals of a Conservation Culture, and that water utilities are best suited to implement them. Rebate programs for water conservation implements are more effective with privately owned houses and apartment buildings with landlords who can recover their investments from the annual rent review process. In the social housing sector where the extended public/non-profit sector is the landlord, large-scale water conservation replacement is but one competitor for scarce capital reserve funds.

Out of the fifty buildings that participated in SHSC's energy pilot, low-flow toilet replacements are recommended in 33 of the buildings, for a total of 2,886 units. Our audits show that 51,622 m^3 of water will be saved if all 2,886 units were replaced, for a total capital investment of $900,000, with an average payback period of 11 years. The 51,622 m^3 of water saved are achievable by replacing the common 13-litre toilets with the 6-litre or dual-flush 6/3-litre toilets. This reduction in water usage volume translates into 2,116.5 kWh per year in projected energy savings.

SHSC recommends a concerted plan of engagement with a multi-year Low-flow Toilet Replacement Program, including dual-flush units where feasible. SHSC will work with Housing Providers and Ontario-based toilet manufacturers, to design an implementation plan that conserves water, saves energy and spurs low-flow toilet production. Over a ten-year period, 100,000 toilets in social housing units across Ontario will be replaced, saving 1,890,000 m^3 of water usage, and resulting in 78,435 kWh per year in energy savings. At the average price of $310 per toilet installed, the Low-flow Toilet Replacement Program requires $3.1 million per year for a total of $31 million over ten years.

Social Housing Providers across Ontario pay approximately $67 million in water utility costs annually. Water utility charges range from $.73/$m^3$ in Hamilton-Wentworth to $1.57/$m^3$ in Durham Region. Savings from 1.9 million m^3 of water usage have profound effects on the Housing Providers' overall utility budgets, and can be applied to additional energy retrofit measures.

Measure 4: Lighting Replacement

Lighting replacement is a pervasive measure that produces immediate results that can be replicated in just about any environment. Many Housing Providers recognize the benefits in energy savings resulting from lighting replacement, and have factored it into their on-going upkeep and maintenance plans. Depending on the actual circumstance and available funds, Housing Providers replace existing lighting with energy efficient products as they burn out, or as a part of a combined lighting and fixture replacement scheme.

Housing Providers are likely to replace lighting in areas that they are responsible for, including lobby, laundry room, stairwell, refuge facility and parking facility. Lighting replacement inside individual housing units is often left to the residents' decisions. SHSC's survey showed that Housing Providers pay 82% of the electricity costs in social housing, while residents pay for the remaining 18%. For those residents who do not pay for energy costs directly, many are not aware of the net benefit of energy conservation. Moreover, lighting incentive programs available through Local Distribution Companies such as Compact Fluorescent Light (CFL) two-for-one-purchase offers, are marketed primarily to households who have direct billing accounts with the utilities, thereby missing conservation opportunities in social housing households.

SHSC recommends a Lighting Replacement Program that aims at residents in social housing households across Ontario. Our energy pilot has identified 23 buildings for in-suite lighting retrofits, out of a total of 50 buildings. Based on this, and our continuing discussion with Housing Providers and municipal Service Managers, we arrive at the need for a large-scale lighting replacement program to fully address this demand management potential.

Working with Housing Providers and their building managers, the Lighting Replacement Program will provide CFL bulbs to social housing households. SHSC will seek out and recommend the best products available based on longevity, price and risk assessment. Over five years, 500,000 CFL bulbs will be installed in 125,000 social housing households, saving a total of 18,000,000kWh or 64,800 GJ. At an average of $5 per bulb, the Lighting Replacement program requires $500,000 per year for a total of $2.5 million over five years. This five-year time-line will complement the planned full-deployment of SMART meters across Ontario.

Measure 5: Market Readiness Interface

In order to maximize demand management opportunities in Ontario, wider sectors such as social housing, must work to identify and implement innovative products for energy end-user installation. SHSC's Market Readiness Interface approach will meet this need at the residential building level. The Corporation's partnership with CMHC, the Ministry of Energy, and Local Distribution Companies province-wide will allow SHSC to explore feasible applications for renewable technologies, including small wind turbines, geothermal heating and cooling systems, and heat storage units, as well as innovative lighting technologies such as Light Emitting Diodes (LEDs), sensor switches, and voltage regulators.

SHSC's role as a direct channel to the social housing sector (including the energy users, building operators, and municipal Service Managers) allows for direct and sustainable implementation of these measures, as well as monitoring and reporting on results. Since the exact energy savings of many of these devices has yet to be determined unequivocally, particularly as the technology continues to evolve, the social housing sector will be an invaluable interface between product developers and the market place.

Our Pilot has identified a number of applications for renewable energy source and/or innovative devices for trial installations. These test sites will allow SHSC to work with product developers in determining the market readiness of these products in the residential housing sector. This approach has the benefit of market replication for both public and private housing. Moreover, using Energy Management System, SHSC will document and report on the best practices and outcomes of these measures through individual, aggregate, and summary reports.

SHSC recommends a three-year Market Readiness Interface initiative, at $100,000 per year for a total of $300,000, to implement and test innovative and renewable energy products.

Strategy 2: Resident Energy Awareness and Practices (REAP)

Energy conservation in the social housing sector is characterized by a complex split incentive environment. A need to identify potential incentives to encourage energy conservation among social housing residents requires an understanding of how energy costs are paid for, and who is affected when consumption increases and/or when energy costs go up. A survey conducted by SHSC's showed that Housing Providers pay 82% of the electricity costs in social housing, while residents pay the remaining 18%.

The gross costs associated with housing a social assistance recipient in social housing are subsidized by two complex pieces of legislation, which are cost-shared in different ways. The gross housing costs of a social housing resident who also receives social assistance are covered through a rent-geared-to-income (RGI) subsidy governed by the Social Housing Reform Act (SHRA) and an allowance provided by either Ontario Works (OW) or the Ontario Disability Support Program (ODSP).

For those residents who are not responsible for energy costs, many are not aware of the net benefit of energy conservation. Experience gleaned from energy programs in California, in Montreal and elsewhere suggests that energy awareness is an important aspect in ensuring the success of energy retrofit implementation. Housing Providers, Service Managers and utility companies province wide have indicated to SHSC the need for a resident engagement program with tools to reach both the social housing sector and low-income sector to maximize their conservation efforts.

SHSC recommends a Resident Energy Awareness and Practices (REAP) program, to provide energy advocacy for residents along side with implementing energy measures. REAP is a full-menu energy conservation program available to Housing Providers and municipal Service Managers. This menu includes effective and proven communications and implementation tools, with the intended outcome of engaging social housing residents on both conservation ideals and incentives based on the public good.

REAP is best applied along with other energy retrofit measures, where the Housing Provider and Service Managers have already demonstrated their commitment to conservation by investing in capital retrofits. Residents are more likely to do their share if they are equal partners, and more likely to adopt conservation-minded practices. SHSC has worked with environmental groups, utilities, Housing Providers and a social marketing firm, on the design and delivery of community-specific energy awareness modules.

The REAP menu includes: articles for newsletters, demonstration examples, best practices, flyers, speaking notes, speakers bureau, group workshops and audio-visual presentations. Our social marketing firm has successfully utilized a community animation model, where several residents from their own buildings are trained as animators to raise the energy awareness of other residents. This train-the-trainer community development model supports program ownership and is responsive to the residents' cultural and linguistic needs.

To further overcome energy consumption-apathy due to the lack of cost-transparency, REAP provides a community incentive formula where measurable energy savings are

transformed into community amenities, rewards and/or recognition. At the start of the retrofit, residents are asked to identify common amenities that they would like to see in their buildings. Based on the amount of energy saved at a pre-determined interval, small grants will be made available as community-wide conservation incentives. These incentives will pay for the agreed-upon amenities, such as playgrounds, recreation equipment, community arts activities etc.

SHSC recommends a five-year Resident Energy Awareness & Practices program, at $400,000 per year for a total of $2 million, to be deployed along side the lighting retrofit and other retrofit measures. Forty multi-unit buildings per year will have the opportunity to participate in REAP, for a total of 200 buildings over five years.

Strategy 3: Energy Efficient New Construction Investment

National and provincial affordable housing programs generally provide matching funding for standard construction methods and designs. Certain NRCan, CMHC and gas utility funding initiatives provide incentives for design upgrades to reach higher energy efficiency standards. While these design upgrade incentives are necessary and vital, SHSC has identified the need for energy efficient investment in new construction to fund incremental costs over and above national building code standards.

To address this investment gap, SHSC proposes a two-pronged strategy:

Measure 1 -- Establish energy efficient design standards, including deployment of renewable energy applications, for new construction in social housing;

Measure 2 -- Establish a multi-year funding program providing upfront incentives and zero-interest loans to energy efficient financing for new social housing construction.

It is particularly encouraging that the Government of Ontario is once again providing resources to construct much-needed affordable housing stock. The newly approved federal 2005 Budget Plan with an additional $1.6 billion for the construction of new affordable housing nation-wide will go a long way. This is a once-in-a-generation opportunity to change the fundamental energy efficient new construction standards in the social housing sector, and towards Canada's commitment to the Kyoto Protocol.

SHSC recommends an investment of $40 million from the federal $1.6 billion new affordable housing funding, to be administered through a contractual agreement among the Ministry of Energy, the Ministry of Municipal Affairs and Housing, and SHSC. This Energy Efficient New Construction Investment will be a part of the overall Sectoral CDM Fund, including a one-time infusion of $100,000 to establish social housing energy efficient design standards, and a $4 million per year multi-year funding program for upfront incentives and incremental financing for energy efficiency.

The social housing energy efficient design standards will include provisions for multi-unit buildings, low-rise and townhouses, and for renewable energy applications. These design standards are applicable to both public and private affordable housing stock. The multi-year funding program will provide the necessary upfront incentives for social Housing Providers to incorporate energy efficient construction methods and products right from the beginning, to a standard that is 25% more energy efficient than required by the Model National Energy Code for Buildings.

Conclusion

SHSC believes that the strategy set out in this document is a prudent and effective approach in helping to achieve the Province's energy conservation and demand management goals. This strategy addresses many of the potential initiatives outlined in the Minister's letter and represents a responsible and measurable approach in SHSC's implementation of a social housing sectoral CDM Strategy.

SHSC looks forward to the OPA recommending this strategy to the Minister and the implementation of these initiatives.

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Strategy Budget and Timeline Summary

	Year One	Year Two	Year Three	Year Four	Year Five	Year Six	Year Seven	Year Eight	Year Nine	Year Ten
Refrigerator Replacement	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000
Install Solar Hot Water Heating	$500,000	$550,000	$600,000	$650,000	$700,000	$800,000	$900,000	$1,000,000	$1,100,000	$1,200,000
Low-flow Toilet Replacement	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000	$3,100,000
Lighting Replacement	$500,000	$500,000	$500,000	$500,000	$500,000					
Market Readiness Interface	$100,000	$100,000	$100,000							
Resident Energy Awareness & Practices (REAP)	$400,000	$400,000	$400,000	$400,000	$400,000					
Energy Efficient New Construction Design Standards	$100,000									
Energy Efficient New Construction Investment	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000	$4,000,000
Program Administration and Accountability	$150,000	$150,000	$150,000	$150,000	$150,000	$100,000	$100,000	$100,000	$100,000	$100,000
TOTAL	12,850,000	12,800,000	12,850,000	12,800,000	12,850,000	12,000,000	12,100,000	12,200,000	12,300,000	12,400,000

ONTARIO's SUPPLY MIX INTO THE FUTURE

Proposals from The Society of Energy Professionals

August 26, 2005

INTRODUCTION

For a long time the connection between the availability and affordability of electricity and social and economic development has been recognized. Electricity powers industry and the institutions of our public life, it lights, cools and heats our homes and workplaces and it mobilizes the public transportation of our cities. Electricity is a vital service – vital to meeting basic human needs, vital to developing our standard of life, vital to realizing our potential.

But for many years Ontarians have become increasingly reliant on fuel sources for the generation of electricity that are now recognized to be harmful to the environment and to human health. Today, issues of electricity are necessarily also issues of the environment.

The challenge for electricity system planning becomes one of balancing these oft-times competing public policy demands on our electricity industry. Adding to this challenge is the fact that the electricity system, itself, imposes its own limitations – in effect, its own demands -- on public policy. These limitations take the form of technical constraints, uncertainties and risks posed by different resource choices and the integration thereof.

The Society of Energy Professionals believes that the electricity industry can continue to contribute to the social and economic objectives of this Province through the provision of reliable and safe electricity at stable and reasonable prices while at the same time restructuring the Province's supply mix in accordance with a carbon mitigation strategy. The Society's carbon mitigation strategy has the following component parts:

1. **Conservation**
2. **Load Shifting**
    a. **Development of pumped storage generation, and**
    b. **Refurbishment of existing nuclear assets where economic and development of new-build nuclear generation**
3. **Maximization of renewable energy sources**
    a. **Enhancement of existing and development of new hydroelectric potential**
    b. **Development of wind generation**

The Society believes that this strategy will enable the phasing out of natural gas-fired generation in Ontario and the return of coal-fired generation to the role of peaking generation in Ontario's supply mix.

Mitigating our Reliance on Carbon-Based Fuels for Electricity Generation

For a large portion of the 20th century Ontarians relied exclusively on water for the generation of electricity. Today, however, hydroelectric power accounts for only one-quarter of our generation capacity and provides a similar fraction of our electricity production. Over the course of the century, much of the growth in demand for electricity has been met through the use of fossil fuels – originally coal (and oil) and latterly natural gas.

Today, forty percent of Ontario's generation capacity comes in the form of fossil fuel generating stations. These stations provide one-quarter of total electricity needs and two-thirds of non-baseload electricity. Ontario's dependence on these stations for meeting demand for electricity has been never been more evident than through the Summer of 2005. Notably, Ontario has become a net importer of electricity in every month since the closure of Lakeview GS in April of 2005.

The government's coal replacement plan (CRP) entrenches this dependence on fossil fuels to meet Ontario's increasing appetite for electricity. The CRP is not a plan to transition away from the use of fossil fuels for electricity generation but rather a plan that leads inevitably to a shift from a reliance on coal-fired generation to a dependence on natural gas for electricity generation – including the use of natural gas for baseload generation. The reasons for this dynamic are as follows:

1. Operating characteristics of coal-fired generation

   Coal supply has historically provided Ontario's electricity system with flexible generation. Replacement supply must have similar characteristics to provide operating flexibility and sustained energy production as and when it is needed. In practical terms gas-fired generation is the only form of generation, presently and sufficiently available, that can approximate the operating characteristics of coal-fired generation.

   The goal of replacing, as opposed to mitigating, coal-fired generation imposes significant limitations on the introduction of new, renewable forms of generation in Ontario's supply mix. Renewable generation is often characterized by its intermittent availability. While this characteristic can be partly overcome through an integrated mix of complementary renewable sources, it remains that renewable sources need to be integrated with dispatchable forms of generation. In short, renewable forms of generation are insufficiently flexible (and

insufficiently available) to replace dispatchable forms of generation such as coal.

2. Industry structure

The clear tendency toward constructing natural gas-fired generators in market-oriented electricity systems has been noted by a number of sources. This dominance owes, in the main, to the principle of "least, first cost." In his address to the North American Power Markets Conference in January, 2005, OPA CEO Jan Carr commented on "the dominance of natural gas fired plants in the ranks of newly built generators in electricity systems that are based on a competitive market structure":

> "Gas fired plants are therefore probably the least risky type of generator in which to invest since so many of their costs can be locked in and the high risk construction period is relatively short. Furthermore, in an electricity market that is dominated by a spot market that pays all bidders the clearing price, the incentive to build lower operating cost generation is dulled. This is especially the case when lower operating costs typically come at the expense of higher capital costs and longer construction times – both of which equate to higher risk."

In their 2004 research paper entitled, "Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario," the Canadian Energy Research Institute identified, and explained in similar terms, the market's preference for natural gas fired generation.

The process of privatization also inhibits the development and deployment of newer renewable energy technologies. In place of the direct levers of a publicly-owned utility to put in place renewable or alternate electricity generating technologies, indirect methods -- such as subsidies and incentive programs for private, for-profit generators to overcome the risk-averse nature of merchant financing -- must be deployed.

Thus far, Ontario has proven to be no exception to this dynamic. The response to the 2,500 MW "Clean Energy Supply" RFP resulted in contracts for over 2,200 megawatts of natural gas-fired generation, no other fuels and only 10 megawatts of demand-response. While failing to redress the current supply/demand imbalance on either the demand or supply side, the CRP simply entrenches fossil fuel generation in Ontario in the form of new, long-term natural gas-fired generation assets. Moreover, a portion of this newly contracted gas-fired generation – at a minimum, that supply which employs co-generation technology -- is intended to supply Ontario with baseload generation capacity.

The Society believes that entrenching fossil fuel generation in Ontario for decades into the future through the construction of new natural gas-fired generation stations is not a tenable public policy position. Rather the Society proposes the following steps in a carbon mitigation strategy in order to realize a future with clean, reliable and economic electricity for Ontario.

PART 1: CONSERVATION

Ontario is facing a serious shortage of electricity. Ontario has been a net importer of electricity in every month since the closure of Lakeview GS in April, 2005. While this set of circumstances calls for significant, immediate capital investment in Ontario's generation resources, it equally calls for significant and immediate action on the demand-side of the demand/supply balance.

Ontario's current shortage of supply occurs in the context of very high per capita energy consumption. According to the Organization of Economic Cooperation and Development, Canada ranks 28th out of the OECD's twenty-nine member states as to per capita energy efficiency. Reducing the demand for electricity as much and as quickly as possible is critical economically and environmentally.

The benefits, direct and ancillary, of conservation are many and significant. Conservation measures tend to:

- improve industrial competitiveness as a result of investment in more efficient technologies;
- Improve housing stock as a result of higher efficiency building standards;
- mitigate damage to the environment;
- reduce the burden on the health care system;
- reduce our dependency on external energy supply and enhance our sovereignty and security; and,
- stabilize electricity prices and other fuel prices by lowering demand.

Restructuring of the electricity industry in many jurisdictions across North America in recent years has prompted a considerable amount of research into the economic benefits of investing in demand-side initiatives (the production of "negawatts") versus supply-side initiatives (the production of megawatts). The research demonstrates, unequivocally, that it is more economical to conserve than to build. Cost estimates of efficiency measures converge on $0.03kW/h (US). Moreover, the type of conservation measures, and consequently the amount of energy savings, that can be considered cost-effective or economical is increasing at a dramatic rate due to rising electricity prices -- particularly in electricity markets such as Ontario where natural gas-fired generation often sets the marginal price – as well as further development of conservation technologies.

The type and impact of conservation initiatives are very sensitive to the structure of the industry. Traditionally, conservation initiatives have been developed by

vertically integrated monopoly utilities operating in the traditional policy context of "least cost resource planning" or "integrated resource planning" (IRP). Under IRP, utilities were required to compare the costs, benefits and functions of a wide array of demand- and supply-side resources, often under alternative future scenarios, to arrive at a well-balanced portfolio of resources that addressed multiple objectives, including minimization of long-term prices and the environmental impacts of electricity production and consumption. It has been estimated that IRP was responsible for $3billion (US) of funding for demand-side management (DSM) programs in the early 1990s in the United States.

With the trend toward deregulation and privatization through the 1990s, vertically integrated utilities were unbundled so that no single entity could be seen as having control over the full suite of demand and supply-side resources. Formal resource planning was abandoned and utilities became passive conveyors of spot market prices. In a deregulated industry structure, markets were supposed to take the place of the obligation of utilities to choose between demand-side and supply-side resources – consumers, rather than vertically integrated utilities were supposed to reveal the appropriate balance between supply-side and demand-side resources and the appropriate options within supply-side and demand-side markets.

However, the unbundling or deregulation of the electricity industry imposes structural disincentives to conservation. To the extent that generation revenues are ultimately based on competitive market prices and transmission and distribution revenues are based on volume of electricity conveyed, conflicts emerge between a) the interests of generators in higher generation prices and the effects of some DSM programs to reduce demand and dampen market prices, and, b) the interests of transmission and distribution utilities and the effect of DSM measures to limit the amount of electricity transmitted and/or distributed and the resulting tariffs. As a result of such structural disincentives imposed by industry restructuring, DSM spending in the United States had fallen from its peak of $3billion in the early 1990s to $1.6billion (US) by 1998.

Adding to the difficulties imposed by the current industry structure and the government's commitment to continue down the path of unbundling Ontario's public generation utility, conservation has its own inherent risks. DSM measures are not dispatchable, for example. But, most significant is the fact that DSM measures rely on consumers, in the main, to adopt more efficient technologies and practices. Consumers, however, may not do so for a variety of reasons, including:

- lack of capital to invest in the technology or practice;
- concern about the ability of the investment to pay back;
- preference for the lowest first cost rather than the lowest life-cycle cost (ie a high implicit discount rate);
- preference for familiar products or practices; and,

- lack of information about the availability of technologies and practices and lack of time to act on the information.

Moreover, Ontario currently has no existing conservation culture, infrastructure, regulatory regime or developed demand-side markets upon which to found aggressive demand-side initiatives.

Some historical examples of leadership in electricity conservation, however, can provide Ontario with some sense of its own conservation potential. While North American examples are limited, the cases of California and British Columbia are instructive. Since the mid-1970s, California has led the way in North America in electricity efficiency, holding per capita consumption virtually constant over 25 years. Through this period, economic output per unit of electricity consumed has increased by 40% in California while increasing by only 8% in the rest of the United States. The implementation of high appliance and building efficiency standards is estimated to have reduced demand by 10,000MW. A further 1,000MW of lasting efficiency measures were put in place during the state's electricity crisis in 2001-2002. BC Hydro's "Power Smart" program, initiated in the 1990s resulted in an estimated 2500GWh of annual energy savings (or 5% of total energy usage) by 2000.

Forecasting conservation potential is, however, somewhat problematic in light of some fluidity in the structure of Ontario's electricity industry and in light of the inherent risks in DSM initiatives. Forecasts of conservation potential, therefore, often distinguish between "technically induced" potential, "economic potential" (ie the application of all cost-effective measures) and categories incorporating even more risk-averse assumptions (eg. "achievable"). Further, in some cases, even more conservative assumptions can be built into forecasts of the potential savings of DSM programming. For example, BC Hydro and a variety of forecasts performed in the California context, focus only on the conservation potential of existing, commercially available and cost-effective "hard-wire" solutions that, a) rely only minimally, if at all, on changes in consumer behaviour and, b) are intended to bring about long-term efficiency gains. Out of scope, therefore, are prototype technologies (eg. magnetic refrigeration) and alternative fuel types (eg. district cooling from deep lake or sea water).

The following represents a summary of forecasts of conservation potential from different jurisdictions:

CONSERVATION POTENTIAL						
	TOTAL ENERGY SAVINGS (GWh/yr)			PEAK DEMAND REDUCTIONS (MW)		
	Maximum Technical	Economic	Achievable	Maximum Technical	Economic	Achievable
10 Years Out						
B.C.* 2000-2010		10,807 20%	3,455 – 5,257 7 – 10%		1,634 20%	491 - 754 6 – 9%
California 2001-11**	56,000 18%	40,000 13%	19,000 - 30,000 6 to 10%	15,000 22%	10,000 15%	3500 - 5,900 6 - 9%
Ontario+ 2005-2015		57,000 33%			11,400 40%	
Ontario++ 2005-2015						2500 9%
15 Years Out						
B.C.* 2000-2015		12,462 23%	5,835 – 8,222 11 - 15%		1,879 22%	842 – 1,204 10 - 14%
Ontario+ (2020)		79,100 44%			14,850 50%	
Ontario++ 2005-2020						3,270 11%

* "BC Hydro Conservation Potential Review 2002," BC Hydro, May 2003

** "California's Secret Energy Surplus: The Potential for Energy Efficiency," The Energy Foundation and The Hewlett Foundation, September 2002

\+ "Power for the Future: Towards a Sustainable Electricity System for Ontario," Pembina Institute for Appropriate Development and the Canadian Environmental Law Association, May 2004.

++ "Tough Choices: Addressing Ontario's Power Needs," Electricity Conservation and Supply Task Force, January 2004. (Note: The ECSTF did not provide a 10 year forecast. The peak demand savings identified for both ECSTF 10 year and 15 year forecasts are based on a) the ECSTF's suggestion that "aggressive conservation" could reduce demand growth to 0.5% per year, and b) the IMO's 10 year "high growth"demand scenario extrapolated to 2020.)

Society Supply Mix Proposal 1:

The inherent risks in excessive reliance on a particular resource in the supply/demand mix leads to the prudent distinction between what are economic or cost-effective measures and what is, in more practical terms, achievable. This distinction should be mirrored in the difference between conservation policy and conservation planning. Therefore, the Society encourages the adoption of a conservation policy that has as its objective the implementation of all economic conservation initiatives taking externalities, such as social and environmental factors, into consideration. Within such a policy context, the Society believes that 7% and 10% reductions in peak demand and total energy consumption in Ontario by 2015 and 2020, respectively, are achievable and form reasonable planning assumptions. Further, in light of the longevity of capital stock, The Society calls for the immediate implementation of conservation measures so that existing energy efficiency technologies can be embedded in new capital stock.

PART 2: LOAD SHIFTING

Most analyses of conservation potential incorporate the notion of load shifting or demand response under the broad category of conservation. In the context of the Society's carbon mitigation strategy, however, load shifting warrants separate focus.

Load shifting accomplishes a number of valuable objectives.

1. Reduced price

A reconfiguration of the load curve allows Ontarians to rely more heavily on baseload forms of electricity generation and less heavily on peak (less efficient) forms of generation. Baseload generation in Ontario is a mix of hydroelectric and nuclear power and, as such, is relatively inexpensive. The levelized unit electricity cost (LUEC) for Ontario's baseload hydroelectric facilities is negligible as costs are spread out over decades of service with virtually no cost for the fuel (water). LUECs for Ontario's current nuclear assets is estimated to be between 3.5 and 5.0 cents/kWh including overheads. A recent study by the Canadian Energy Research Institute (entitled "Levelised Unit Electricity Cost Comparison of Alternate Technologies for Baseload Generation in Ontario," August 2004) comparing LUECs for various baseload generation options showed LUECs for new, publicly-financed nuclear power to be more 1 to 2 cents/kWh lower (5.3 to 6.3 cents/kWh) than merchant-financed gas generation (7.5 cents/kWh). Moreover, this study assumed a base price for natural gas approximately 40 percent below current spot market prices.

Peak generation, on the other hand is significantly more expensive due to the generator's need to recover capital and fixed costs over a much smaller amount of run time of energy output. In Ontario, this problem is exacerbated as the government maintains its commitment to close publicly-owned and cheap coal-fired generation and procure more expensive merchant gas generation to replace it in the supply mix. Moreover, in the context of a market system, the slope of the price curve increases sharply as demand nears its peak. The Electrical Power Research Institute found, for example, that a 2 percent reduction in energy usage in California in the Summer of 2001 would have cut wholesale electricity expenditures by $700 million.

2. Mitigation of harm to the environment and human health.

The forms of baseload generation that make up Ontario's baseload supply are, generally, more benign than peak forms of generation. Approximately 20 percent of Ontario's baseload supply is provided by hydroelectric power and the rest is provided by nuclear power. While concern exists about the long-term implications of nuclear waste disposal, nuclear power does not

contribute in any significant way to the release of greenhouse gases (GHGs) to the atmosphere or the release of emissions that are harmful to human health and detrimental to the environment. On the other hand, two-thirds (approximately 40 TWh in 2004) of Ontario's remaining (non-baseload) energy needs are provided by fossil fuel generation.

Part 2A: Pumped Storage Generation

Load shifting is, in the main, not incorporated into demand forecasting because most forms of load-shifting or demand response are entirely dependent on induced, but most often voluntary, energy consumption habits. Therefore, load shifting or demand response programming is not, generally, reliable for planning purposes.

However, Ontario is able, through the development and use of its existing and potential pumped storage facilities to, in effect, shift considerable load to off-peak periods. It is estimated that the current hydroelectric infrastructure would permit the development of 2300 MW of pumped storage generation (PSG) and that the potential exists for an additional 3300 MW of PSG at sites requiring the development of upper reservoirs.

Society Supply Mix Proposal 2:

As the use of Ontario's pumped storage generation (PSG) potential allows for the increased reliance on baseload forms of generation and the consequent mitigation of fossil fuel generation to meet non-baseload demand, The Society proposes that, a) existing pumped storage infrastructure be brought into service and, b) the Province explore the feasibility of developing the potential for additional PSG capacity.

Part 2B: Nuclear Power

While aggressive conservation efforts can slow, perhaps even neutralize, the growth of Ontario's electricity demands, our need for baseload generating capacity can be expected to continue to grow assuming a viable Ontario economy. Further, sufficient baseload capacity is a prerequisite for meaningful load-shifting efforts to meet with success. For example, the Society's proposal (above) to shift significant load to off-peak periods through the use of pumped storage generation is very much dependent on a corresponding increase in baseload generation capacity.

Moreover, the recent commitment by Ontario Power Generation to "mothball" Pickering A reactor units 2 and 3 has made Ontario's supply even more dire and the need to commit to a plan to refurbish existing nuclear assets and build new nuclear assets even more imperative. Ontario relies on its fleet of nuclear reactors for approximately half of its electrical energy. Ontario's renewable

resources do not come in sufficient supply or with the necessary operational characteristics to meaningfully reduce the requirement for increased nuclear capacity in Ontario. However, all sixteen of Ontario's currently operational reactors (including Pickering A unit 1) will reach their end-of-life between 2010 and 2020.

Society Supply Mix Proposal 3:

The Society proposes that the Province commit to a plan to refurbish existing nuclear assets, where economic, and build new nuclear assets to accommodate organic growth in demand for baseload generation. Further, the Society proposes that this plan a) incorporate the increased need for baseload capacity to accommodate the Society's proposal with respect to pumped storage generation and, b) incorporate sufficient capacity to allow for the success of other meaningful demand response programming as it might arise in the future.

PART 3: RENEWABLE ENERGY RESOURCES

Ontario is rich in renewable resources from which electricity can be generated. The Society of Energy Professionals believes that Ontario must commit to the development of a long-term plan for sustainable energy sources together with sustainable levels of energy consumption. While some sources of renewable energy hold out promise for future exploitation, the economic incorporation of these resources into Ontario's supply mix depends on significant technological advances (eg. solar energy). This is not the case with hydroelectric power and wind energy.

While the technology to further exploit Ontario's hydroelectric power has existed for a considerable period of time, rising electricity prices has rendered significant hydroelectric resources increasingly economic. Rapid technological advances in wind generation around the globe have also made wind a significant, economic resource for electricity generation in Ontario. The Society supports the maximum, economic exploitation of these resources in order to mitigate the use of fossil fuels for electricity generation.

Part 3A: Hydroelectric Power

Generally, there are two types of hydroelectric plants: "run of the river" in which water is used at the rate supplied by the natural flows of the river; and, peaking plants which store water behind a dam and release it when generation is required. Peaking hydroelectric plants provide excellent operational flexibility as each unit can be stopped and started (and modulates) relatively quickly to meet system needs. Peaking hydroelectric plants complement nuclear baseload

production well and are particularly useful for mitigating the use of fossil fuel generators.

As water is the "fuel" in hydroelectric generation, it is renewable -- particularly run of the river generation -- and generally, from an environmental standpoint, low impact. In particular, it has no direct effects on Ontario's air quality. The development of peaking plants, however, does have environmental effects in the form of access roads, flooding, fluctuations in water levels and flows, erosion and the potential for methane release and the release of naturally occurring, biologically active mercury in the flood zone to the environment. However, the development of such plants can also have environmental benefits in the form of flooding and erosion control and new habitats for waterfowl.

In 1989, Ontario Hydro published a "Demand/Supply Plan Report" (the Report) as one of a series of documents issued under the title, "Providing the Balance of Power: Ontario Hydro's Plan to Serve Customers' Electricity Needs." The Report identified "Ontario's total theoretical hydraulic power potential" as 19,900 MW of capacity and 82.8 TWh of average annual energy. Of this total capacity, only 7500 MW has been developed yielding less than half of the potential energy supply from Ontario's water resources.

The Report analyzed the technical, environmental and economic feasibility of developing the residual 12,400 MW of capacity and concluded with a plan for the development of nearly 3,000 MW of hydroelectric capacity through the redevelopment or extension of existing plants/systems and the development of new hydroelectric plants. (A subsequent 1996 Ontario Hydro Report reconfirmed the existence of approximately 3000 MW of capacity at existing hydroelectric generating stations and dams.)

Since Ontario Hydro undertook its feasibility analysis of the residual hydroelectric generation capacity in 1989, a number of the technical, environmental and economic assumptions have changed significantly. For example, of the residual hydroelectric potential in Ontario, the Report identified nearly 1000 MW (and 5.7 TWh of annual energy) of "small hydro" capacity. (Small hydro is defined as sites with less than 5 MW of installed capacity.) In 1989, both economic assumptions and technological capabilities dictated the development of large centralized hydroelectric stations. Small hydro was considered unfeasible. Further, at the time of the analysis, the price of electricity was significantly lower ($17 -- $20/MWh) than current market clearing prices. Other factors affecting an assessment of the feasibility of exploiting the residual hydroelectric resources have also changed since 1989, as for example:

- The price of substitute fuels, such as natural gas, have increased more than 450 percent (see above re natural gas);
- The life cycle of hydroelectric plants is longer than originally anticipated;
- Turbine technologies have increased turbine-generator efficiency from <30% 100 years ago to >90% today;

- Experience with respect to design/capacities of plants (more recent plants had been designed for greater than actual water flow thus reducing their capacity factor);
- Change in cost assumptions due to industry restructuring (eg. original feasibility study incorporated transmission development into cost assumptions);
- Concern with respect to the environmental impacts of hydroelectric development relative to present-day concerns with respect to greenhouse gasses and fossil fuel emissions.

The information provided in the Report in the context of current factors affecting the feasibility of exploiting Ontario's residual hydroelectric resource potential, lead the Society to propose the following:

Society Supply Mix Proposal 4

A. That the development of, and/or efficiency improvements to, hydroelectric generation at the following sites commence immediately:

River/System	Plant/Site	MW (capacity increase)	GWh (annual increase)
Niagara	Beck Diversion	50	1750
	Beck 1 Frequency Conversion	70	
	Beck 2 Rehab	192	
Welland	Lake Gibson	5	40
Mattagami	Smokey Falls	182	508
	Little Long	61	67
	Harmon	68	97
	Kipling	68	93
	Cypress Falls	42	106
Abitibi	Abitibi Canyon	463	1111
	Otter Rapids	174	430
	Nine Mile Rapids	295	726
	Blacksmith Rapids	140	369
	Sand Rapids and Allan Rapids	262	703
Moose	Renison	135	555
Montreal	Ragged Chute	98	177
Little Jackfish	Little Jackfish	132	568
Various	Northeast conversion	9	25
	Lac Seul Powerhouse	14	52
Total		~2400	~5300

B. That all existing hydroelectric generating facilities be reviewed with a view to increasing efficiencies and capacity (eg. including simple but effective methods of increasing the hydraulic head such as lowering tail water levels and the use of flashboards).

C. That amendments to, and/or the development of, regulations be made that would encourage the development of small hydro capacity where it does not compromise environmental integrity.

Part 3B: Wind Energy

Of all the renewable energy sources, apart from hydroelectric, wind is the only renewable that is commercially viable today in significant quantity. The phenomenal and exponential growth of wind generation in jurisdictions around the world suggests that wind energy should no longer be considered an alternative energy source. It has become a mainstream technology for electricity generation, dominated by large wind turbine-generator (WTG) manufacturers such as GE in the U.S. and Vestas in Europe. Today's installed technology is based on turbines rated at 2 – 3.6 MW, but 5 MW (120m rotor diameter) machines are expected by 2010.

The global wind power industry installed about 8,000 MW in each of 2003 and 2004, according to the European Wind Energy Association (EWEA) and the Global Wind Energy Council (GWEC), bringing the world's total wind power generating capacity to 47,317 MW. The total world generating capacity provides enough electricity to supply the equivalent of about 15 million average American homes, or 30 million average European households.

New wind industry investment was worth $9 billion in 2003, up from $7 billion in 2002, making wind generation the fastest growing source of electricity in the world. Europe dominated the global market in 2004, accounting for 72% of the new installations. The countries with the most wind power capacity are now Germany (16,600 MW), Spain (8,260 MW), U.S.A. (6,740 MW), Denmark (3,120 MW), and India (3,000 MW). Growth of the wind sector is widely forecast to continue in the double digits into the next decade, even as the industry matures. A recent survey published by the German Wind Energy Institute (DEWI) reported that the global market could reach 150,000 MW by 2012.

Ontario is estimated to have an abundant supply of wind energy. The Canadian Wind Energy Association (CANWEA) has estimated Ontario's potential installed capacity for developable wind farms at between 2000 and 6000 MW. Moreover, Ontario has higher average wind velocities than Germany, the country with the largest inventory of wind turbine generation in the world today.

As of June, 2005, Canada had 570 MW of installed wind generating capacity with Ontario accounting for only 15 MW of that total. A further 350 MW of wind generation has been procured in Ontario.

A number of studies have demonstrated that renewable energy like wind generation is the most employment-intensive source of energy. Because wind construction and installation projects are site-specific, engineering is required from pre-feasibility studies through to operation and maintenance (although construction and installation counts for the vast majority of employment). CANWEA estimates that over 2000 engineering jobs would be created in meeting their goal of 10,000 MW of wind in Canada by 2010. Increased wind generation activity could also support a robust component-manufacturing sector. Moreover, wind has the same characteristic as other renewable resources – it's indigenous – assisting with the goal of energy self-sufficiency and security of supply.

It is estimated that levelised costs for electricity generated by wind have come down from 30 U.S. cents/kWh in 1980 to about 4 U.S. cents/kWh. Since the fuel is free, the costs associated with wind are mostly initial capital costs. The cost of wind power can vary considerably depending on location and wind speed (since power output is proportional to the cube of wind speed). Costs are expected to decline further (5% annually) due to continuing technological advances, such as taller towers, larger rotors and the development of rotors specifically intended for lower wind speed regimes.

While wind energy is both abundant and predictable, much criticism has been leveled at wind generation for its intermittency and seasonal variability. Through a combination of careful site selection and improving turbine technology, most utility-scale wind developments annually produce an average output equal to about 30% of their rated (nameplate) capacity. In most areas of the world, this average changes with seasonal wind patterns throughout the year. (In Ontario, the winter half of the year accounts for about two-thirds of the year's energy from wind.)

Accurate adequacy assessments and forecasting, therefore, require site-specific data for each wind farm, as well as data accounting for the dispersion of the resource across the province and any seasonal differences in available energy. So, while the capacity of a wind farm with "nameplate" capacity of 100 MW is actually about 30 MW, the capacity number incorporated into adequacy assessments and forecasting may be as low as 10 MW.

Sophisticated approaches for dealing with wind power intermittency have been developed by system operators in Denmark, where wind energy can climb to about half the system's demand during valley hours. Day-ahead weather forecasting, and real- and reactive-power output control on the wind farms have combined to yield a workable system with very high wind power penetration (much higher than Ontario is ever expected to see). The most advanced wind

turbine generator controls take on some of the attributes of electronic stabilizers, using stored energy in the turbine rotor and variable-speed generator technology to compensate for short-term variations in wind velocity.

While the energy output over time from a wind turbine is assured, and delivery is predictable from one to three days ahead, there is no escaping the fact that wind generation must be "firmed" by some dispatchable source of power. This would be an ideal use for stored fossil fuels, as Ontario's fossil fuel plants

- could be ready when needed, but used sparingly to limit total emissions; and,
- are in close proximity to Ontario's highest wind energy sites (typically, wind is best along shorelines) thus limiting transmission costs and impacts for new wind generation farms.

In time, this "firming" function may also be provided by dispatchable biomass generation facilities. Jurisdictions that have integrated wind generation with dispatchable generation estimate that the premium added to wind-generated energy for this "firming" service is only about 0.5 cents per delivered wind kWh.

Apart from the system requirement for wind generation to be integrated with dispatchable forms of generation, wind generation also holds out the opportunity of integration with other renewable resources with complementary seasonal variability. For example, solar energy is most plentiful in the Summer, while hydroelectric is most plentiful in the Spring and Fall. These sources of energy complement the higher output of wind energy in the wintertime (due to the higher density of cold air and stronger winter winds). Wind energy can also be stored year round in the form of water when integrated into pumped storage generation facilities. (See discussion above under "Load Shifting".)

Society Supply Mix Proposal 5

The Society proposes the maximization and integration of Ontario's abundant wind energy into the electricity system in Ontario.

<u>The future of fossil fuel generation in Ontario</u>

Based on the supply profiles of natural gas and coal, The Society believes that, a) natural gas-fired generation is not a sustainable part of Ontario's supply mix and, b) coal-fired generation is an inevitable part of Ontario's supply mix for the foreseeable future. Further, The Society believes that the supply profiles of natural gas and coal provide ample public policy justification for a) phasing out natural gas-fired generation in Ontario and, b) applying current and emerging clean coal technologies to Ontario's coal-fired generation assets.

While production and consumption levels of natural gas in North America are roughly in balance at present (the United States imports 3% of its natural gas in the form of liquefied natural gas (LNG)), demand for natural gas in North America

is anticipated to grow at a pace between 1.5 and 2.0 percent per year into the future. North American natural gas supply cannot keep up with this demand.

In 2004, gas production rose in every region of the world except North America. In fact, production data shows that North America is on an exploration treadmill. In spite of record drilling rates, production of natural gas in Canada fell in 2003 by 3.6% off its 2002 peak. Recently discovered reserves are proving to be smaller and reach maturity faster. Decline rates for underlying production in Western Canada have increase from 7 percent in 1990 to over 20 percent in most recent years. Sable Island reserves, off Canada's east coast, were downgraded by a total of 60 percent over the last three years. These trends are continental, not just Canadian, as US natural gas production appears to have peaked in 2001.

Recent NEB estimates suggest that nearly two-thirds of Canada's discovered resources have been consumed leaving only 7.5 years of proven reserves and another 5 years of possible reserves. British Petroleum estimates Canada's 2004 reserves to production ratio to be 8.8 years. BP's estimate for the United States's reserve to production ratio is only slightly higher at 9.8 years.

Increasing tightness of supply relative to demand has resulted in both higher and increasingly volatile natural gas prices. Natural gas prices have increased approximately 450% over the last decade and a half. The increasing demand and, hence, competition for natural gas has resulted in the annualized standard deviation in gas prices increasing from approximately 20% in 1990 to up to approximately 70% in recent years. The incremental demand for natural gas to replace coal-fired generation under the CRP is estimated to equal 1.2% (800 Mcf per day) of total North American supply. This will significantly exacerbate existing upward pressures on natural gas prices.

It can be expected that these pricing effects will directly flow through to wholesale electricity prices given that fuel costs for natural gas plants can account for more than half of the levelized cost of gas-fired electricity and more than 90% of operating costs. This is particularly problematic in the context of an electricity market in which natural gas largely sets the clearing price for all generation.

Quite apart from market mechanisms, the Canadian Energy Research Institute (CERI), in their recent study comparing levelised unit electricity costs, concluded that, "gas-fired generation for baseload supply looks unattractive in nearly all scenarios due to forecast increases in the price of natural gas." Further, CERI concluded that, "the LUECs of coal and nuclear options are very robust (change little) in response to changes in the price of coal or uranium. The LUEC of gas-fired generation is very sensitive to changes in the fuel price." Due to the price assumptions of natural gas used in the study, CERI's conclusions downplay significantly the economic disadvantage of natural gas-fired generation relative to nuclear and coal-fired options. CERI's study assumed a base price of $6.47 (2003 Cdn $ or $6.70 2005 Cdn. $) at the Dawn, Ontario hub in 2005 and a rate

of increase of 1.8% per year until 2025 with the price remaining constant thereafter. On August 24th, 2005, natural gas reached a price of $11.622 at the Dawn hub, eclipsing the base price assumption used by CERI for their study by almost 75 percent.

Further, while some natural gas price forecasts have anticipated a dampening or moderating effect on natural gas prices of increased LNG imports, recent supply and demand forecasts call into question the very ability of LNG to meet demand -- quite apart from price.

Assumptions concerning future supply of natural gas in North America are very much riding on the prospects of LNG imports. The U.S. Energy Information Administration's (EIA) most recent long-term forecast ("Annual Energy Outlook 2005") estimates that over the next 20 years, total annual imports of LNG will grow from 0.649 Tcf per year (2.9% of total current U.S. natural gas consumption) to 6.37 Tcf per year. This forecast suggests that over the next two decades somewhere between two-thirds and ninety percent (depending on whether or not the new proposed Alaskan natural gas pipeline gets built without significant delays) of the United States's incremental natural gas supply must come from LNG imports. This forecast represents an annual growth rate of LNG imports of over 12 percent starting in 2008 from LNG projects that have yet to be built and shipped on LNG tankers that have yet to be constructed to LNG off-loading facilities that have yet to be approved. Further, prices for LNG will be determined on an international spot market involving a number of players with an even greater appetite for natural gas than exists in North America. And finally, supply of LNG comes from some of the world's least politically stable jurisdictions making security of supply a very real issue – again, quite apart from price.

The supply profile, and consequently price and price forecast, of coal is very different from that of natural gas. According to the National Energy Board, coal accounts for 91% of hydrocarbon reserves (excluding oil sands and oil shale) in North America. North America's reserve to production ratio for coal is estimated to be 235 years, according to BP. BP estimates Canada's reserve to production ratio for coal is estimated to be 100 years. The National Energy Board anticipates that coal prices will decline by 1% per annum until 2015 and then remain stable to 2025.

Society Supply Mix Proposal 6

In light of the supply profile of natural gas, the Society proposes that, a) no new natural gas-fired generating stations be built in Ontario and, b) natural gas-fired generation be phased out of Ontario's supply mix as replacement capacity is available.

Much of the demand for natural gas for electricity generation in recent years flows from its purported environmental advantages as a fuel for the generation of

electricity relative to other fossil fuels. Absent the application of methods by which emissions resulting from coal combustion can be reduced – commonly referred to as "clean coal technologies" -- standard natural gas generation technology, at the burner tip, produces about 40% less nitrogen oxide and carbon dioxide than the coal-fired technology used in Ontario. Similarly, Combined Cycle gas generation produces 97% less nitrogen oxide and approximately 60% less carbon dioxide than Ontario's current coal-fired technology absent emission controls. Moreover, the combustion of natural gas emits virtually no sulphur dioxide or Mercury.

However, currently available (and, in some circumstances in Ontario, currently applied) clean coal technologies are able to significantly mitigate key air pollutants emitted by coal-fired generators. For example:

Facts about existing "clean coal technologies"

Nitrogen Oxide

- Nitrogen oxide reduction technologies come in the form of both combustion controls and post-combustion controls. "Low NOx Burners", for example, can typically achieve nitrogen oxide reductions of between 30 and 65%. In terms of post-combustion technologies, "Selective Non-Catalytic Reduction" processes are able to remove up to 60% of nitrogen oxide while Selective Catalytic Reduction" (SCR) can achieve reductions of 90%.

Sulphur Dioxide

- Sulphur dioxide emissions can be reduced by switching to low-sulphur coal and/or by employing "flue gas de-sulphurization" (FGD) technologies. "Wet" FGD processes can remove over 99% of sulphur dioxide while at the same time removing fine particulate matter and trace metals including mercury and producing a by-product with commercial value, gypsum. Dry and semi-dry FGD technologies are less expensive than wet FGD but are less effective.

Mercury

- Installation of post-combustion controls designed for nitrogen oxide and sulphur dioxide have the co-benefit of significant mercury removal. SCR does not, itself, remove mercury but has the benefit of ionizing mercury, allowing downstream capture of mercury more efficient through sulphur dioxide wet scrubbers or baghouse installation (filter). Wet scrubbers typically result in a 50% removal efficiency.
- Other reduction technologies are available or are being developed that achieve reductions of up to 90%.

Inescapable, however, is the production of greater amounts of carbon dioxide from the burning of coal than the burning of natural gas owing to coal's greater carbon intensity. Because carbon dioxide is not readily broken down or converted to other compounds (unlike nitrogen oxides and sulphur dioxide), efforts to mitigate carbon dioxide emissions from coal-fired generation come in the form of improved combustion efficiency (eg. supercritical, ultra-supercritical and integrated coal gasification combined cycle (IGCC)) as well as exploration of technologies that would permit the capture and sequestration of the gas.

A life-cycle assessment of natural gas would suggest, however, that the relative environmental attributes of coal and natural gas are considerably more complex. Environment Canada, for example, reports that greenhouse gas (GHG) emissions from fossil fuel production alone – that is, not including the combustion of fossil fuels for the purpose of generating electricity -- accounts for 19% of total Canadian GHG emissions. This is equivalent to the total quantity of GHGs emitted by the Canadian electricity generation sector. While not conclusive in and of itself, incorporating this type of information into an environmental (life-cycle) assessment of the relative environmental attributes of natural gas and coal produces a vastly different context for planning the future of Ontario's electricity industry. Furthermore, one can anticipate that this type of assessment will shift in favour of coal-fired generation as the exploration and recovery of the dwindling supply of natural gas incurs greater adverse environmental impacts.

Society Supply Mix Proposal 7

In light of the supply profile of coal, the Society proposes, a) that coal assume a role of peaking generation in the supply mix for the foreseeable future and, b) the continued application of existing and emerging economic clean-coal technologies to Ontario's coal fired-generation assets in order to: increase the efficiency of combustion; reduce harmful emissions; reduce the carbon intensity of the fuel used in the combustion process (eg. through the mix of biomass); and, capture and sequester GHGs.

Respectfully submitted by,

The Society of Energy Professionals
August 26, 2005

Subject: Sumission to OPA
Submission to the Ontario Power Authority re Ontario's Electricity Supply mix and future energy sources.

I would like to comment as an individual on the future mix for Ontario's electricity supplies. But first, I want to make full disclosure: I am a long term employee of Ontario Hydro and it's successor company Ontario Power Generation. I have worked for thirty-three years, twenty years as a generator operator in a coal-fired generating station and the last thirteen as a training officer for the operating trade in the six fossil fueled stations in the OPG fleet. My job has provided me with the opportunity to become familiar with all aspects related to the operation of coal-fired generators as well as oil and natural gas-fired generators.

I believe that the government, by deciding to eliminate coal-fired generation from our energy mix is placing the economic well being of this province in jeopardy. Coal is a fuel which is hundreds of times more plentiful than natural gas, is mined right here in Canada and with the proper equipment can be burned just as cleanly as a natural gas-fired generating plant.

The price of energy

In recent months we have witnessed substantial increases in energy costs, most notably at the gasoline pump, but also in the price of natural gas. Canada's natural gas resources are extremely limited and by some accounts could be eliminated in less than a decade at current consumption levels. As the reserves of natural gas are reduced, the price will increase simply due to the principles of supply and demand.

The economy of this province will be hurt severely by rising energy prices. It makes no sense to needlessly drive the price of electricity up as well by switching to more expensive natural gas generation. Ontario's economy needs affordable and competitively priced electricity.

The best way to do this is via a diverse energy mix that includes hydroelectric, nuclear, coal, oil, gas, wind and other non-traditional sources of supply. This diversity is the best way to provide reliability of supply.

I would like to examine the impact of removal of coal from our generation mix. Our current electricity market operates on a bidding system where electricity generators "offer" their available megawatts to the IESO, the Independent Electricity System Operator at a price that reflects their operating costs. The IESO matches available generation to demand on the power system, choosing to operate the least expensive geerators first and the more expensive generators only as demand increases and requires them to come on stream. In this system, our hydro generators are usually the cheapest to run and therefore run first to meet demand. Then come the Nukes and the fossil plants followed by the more expensive gas plants.

The price of electricity is determined by the most expensive unit that must be operated in order for the IESO to meet market demand. This is important because all generators are then paid that price - the price of the most expensive generator in service - irregardless of their "offer" price. This means that, even though a hydroelectric unit was offered to the IESO at say 3 cents per kilowatt, because a more expensive gas-fired unit at say 9 cents per kilowatt was required to meet demand, the market price becomes the price of the gas unit and all generators are paid 9 cents per kilowatt. In this case the gas unit has "set the market price".

It should be noted that since our market has opened, the market price has been set approximately 50% or more of the time by coal fired generators. Therefore the market price has been determined by the operating cost of the coal generator, usually at about 5 cents per kilowatt.

By removing coal from our energy mix, there will be no alternative but to run the gas-fired generators and their higher operating cost will more often than not determine the market price. Electricity prices will likely double as a direct result of the forced retirement of our coal-fired generators.

Misinformation about coal

There is a great deal of misinformation about coal as a "dirty" fuel, with much of that information having been promoted by persons with vested interests in the natural gas industry. (see reference 1)

Coal emissions are not the major contributor to air pollution in Ontario. The transportation sector is the highest contributor of NOx (63%)

Greater than 50% of smog in Ontario originates in the US. The electricity sector including gas, oil and coal, accounts for only 15% of Ontario's emissions and therefore less than 7.5% of Ontario's smog.

Despite widespread public opinion, "it is imposible to identify which specific deaths that occur over a given period of time are actually attributable to air pollution".

An alternative

There is an alternative that the Ontario government has failed to give proper consideration. That is clean coal technology. Our Lambton station currently has two of the cleanest burning coal units in North America. These units are equipped with scrubbers. Unfortunately, these are the only units in the fleet with this technology. Other units, including those at Nanticoke have been retro-fitted with low NOx burners and selective catalytic reduction (SCRs) which help greatly to reduce NOx emissions, but not sulphur. Some of our units are also equipped with Flue Gas Conditioning (FGC) which allows the burning of low sulphur coals for which our boilers were not originally designed.

However, there is much more that can be done. Our exisiting coal units can be retro-fitted with scrubbers to further reduce sulphur emissions. Even with the cost of adding scrubber equipment, coal units can be cheaper to operate than gas-fired units. New coal plants with state of the art emissions controls can be built cheaper and quicker than new nuclear units. An example is the Genessee Phase 3 unit operated by EPCOR near Edmonton Alberta, which claims to have emissions on a par with a comparable size gas unit. The technology for clean coal generation is available today.

The federal government makes repeated reference to the increased use of clean coal technology in its Project Green plan (www.climatechange.gc.ca). Ontario could choose to be a leader in clean coal technology while at the same time keeping our energy costs from rising astronomically.

Conclusion

1) the current path of closing coal generators and replacing them with gas-fired generators will result in significant upward pressure on electricity rates in Ontario, which will be devastating to business and industry in the province but is totally unnecessary!

2) natural gas reserves are limited and increased demand will lead to further price increases

3) coal reserves are plentiful and prices are expected to remain relatively stable

4) there are alternatives to shutting down our coal generators that the government is ignoring. Clean coal technology must be part of our generation mix.

5) conservation and renewable source such as wind must be encouraged, but they alone cannot be expected to meet our increased demand.

References

1. The Switch to Natural Gas - An Unaffordable Option, the Clean Affordable Energy Alliance, http://www.caealliance.com

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3. News Release: Ontario Government in the Dark on Coal Plant Closings: Shutting Down Coal-fired Power Plants will do more Harm than Good
http://www.fraserinstitute.ca/shared/readmore.asp?sNav=nr&id=640

Bill Strong

August 26 2005.

To the Ontario Power Authority,

Here are some considerations in reply to your request for feedback on the energy supply mix to generate electricity in Ontario.

Recommendations with respect to **conservation** can best be accomplished through a review of the standards set in building codes and home appliances,

Renewable energy such as wind has a limited role due to its low 25 % reliability. While we should encourage its use in the energy supply mix whenever it is available, we must also realize that its capital and maintenance costs are considerable for each Megawatt output.

While both **conservation and renewable energy** are laudable approaches that need to be further developed and encouraged, we must understand their applications as well as the limits of each in the overall scope of electricity supply.

BASE LOAD ENERGY SUPPLY FOR ELECTRICITY:
Can be referred to as the engine that drives the Ontario economy. While our nuclear fleet supplies our steady state base load, coal fired generation supplies 25 % of base load with the advantage of its capability to fluctuate load production according to demand for power.

INTERMEDIATE AND PEAK ENERGY SUPPLIES:
In addition to nuclear and coal as base load producers, expensive Gas fired electric generation and costly imports supply our needs for electricity when demand exceeds our base load supply.

While both gas and imports have an important role in the production of electricity when demand exceeds base load, we must ensure that the %age share of base load in the total demand for electricity supply does not erode any further.
Increased reliance on gas fired generation and imports will drive the cost of the end product even higher beyond anyone's control at the expense of the ratepayer.

The **TRUE** cost per megawatt of each energy supply in the mix should be **TRANSPARENT**, including all details of any Government awarded contracts to non-utility generation should be made public so that Ontario ratepayers are well informed on the energy supply issues.
When we look at the per Megawatt cost supplied by each energy source from an aforementioned transparent perspective, the solution on how to proceed will become very clear.

We will need to expand our base load production, nuclear and coal if indeed we want to have some price control in the electric production sector.
Cost will simply be the major factor in any successful review of the future energy supply mix in the production of electricity and without transparency of true costs of each energy supply, we will fail to address the needs of all Ontario electric consumers, small and large.

Gas fired generation for base load should only be allowed when it becomes competitive and its supply issues are addressed.
If gas fired generation at this time is allowed to replace coal, be prepared to answer the limited gas supply issues, as well as the cost of gas. The results of this approach without further review could be detrimental to our economy.

The cost of Gas has more than doubled over the last couple of years. If allowed to replace coal with base load gas generation, the limited supply of gas will not only drive the cost of gas beyond reach but in turn the cost of base load electricity through the roof.

This situation has the real potential of adversely affecting our economy and wipe out profit margins for many employers in the industrial, commercial and agricultural sectors. Such increases in the cost of base load electricity will also affect our Hospitals and School Boards who already operate under severe budget pressures. The home consumer will not be spared from unaffordable increases in both gas and electricity costs.

Electricity from Gas generation will never be able to compete in the production of base load with nuclear and coal. We all know that from our existing energy supply mix.
The know gas reserves are dwindling as demand and prices increase, when knowing coal reserves have an abundant supply for the next 250 years in North America. This should play a major role in future planning of electricity supply.
The limited supply of gas has many higher efficiency applications in Industry, Agriculture and Commerce. Home furnaces for example have a gas efficiency rate of 95 %. Gas used to produce electricity has a 35% efficiency rate. Let the ratepayer be the Judge.

Should the present Ontario Energy policies be allowed to proceed and shut down all coal fired generating stations and replace the base load production with gas, the ratepayers better be warned about the consequences. It certainly would not be in consumers' interest to produce base load at the same cost as peak load. **The gas lobby would be the only beneficiary at the expense of the consumers.**

To write off valuable taxpayer assets through the closure of all productive and profitable coal fired stations is paramount to squandering our capital resources.
Then switching from coal to gas fired generating stations will furthermore require a multi billion dollar capital investment funded by taxpayers.
Just consider the new infrastructure costs that will be required to switch from coal to gas: construction of new generating stations, new gas pipelines, new electric distribution lines and transformers.

All these unnecessary new capital costs will have a net result that will drive the cost of gas as well as electricity through the roof at a time when there is uncertainty about the future supply of gas that will fuel these proposed new gas generating stations. The appetite for gas of these generators is just enormous for the amount of electricity they produce at exuberant high rates.

Our Southern neighbor has already clearly demonstrated their fundamental mistake in switching from coal to gas.
About 8 to 10 years ago, the US started bringing on line gas fired generating stations, who are now sitting idle most of the time as a result of the high cost of gas in the production of electricity.
In order to repair some of the damage as a result of lack of planning, the US now has more than 70 coal fired generating stations in the planning stage and under construction.
We can objectively conclude that when Ontario runs out of gas as a result of base load electric production, we will always be able to import coal fired electricity **at any cost** from our friendly neighbour.

Under these circumstances, why then should Ontario even consider switching from coal to gas and repeat the errors made by the US nearly a decade ago?

The issue of clean emissions from coal fired stations need to be addressed without delay.
It simply is a crime against the environment for any Ministry of Energy to delay the refurbishing of all coal fired generation in Ontario with existing clean emission technologies.
This could be accomplished at a fraction of the infrastructure cost it would take to switch from coal to gas in the production of Ontario electricity.
Clean emission technologies for coal fired generation has proven to be effective and successful in densely populated areas in Western Europe where environmental issues are taken very seriously.
Therefore there is no reasons why clean emission control technologies on coal fired generating stations would not be either functional or acceptable in Ontario.
I find it ironic that any Minister of Energy who is supposedly looking for solutions had the **"wisdom"** to keep clean emission coal fired generation out of the Ontario electricity supply mix when at the same time it requested **advice** from the OPA on the energy supply mix. Could this be an oxymoron as I understand it?

If indeed it is our mission going forward, to provide this Province with a competitive, affordable, clean emission and reliable electric supply system upon which a successful economy has been built over many decades, then provide the consumer with affordable and environmental friendly power that will also make our economy competitive.
Respectfully submitted.

Paul Serruys

Dear Sir/Madam

I am responding to the task assigned to OPA by the Energy Minister regarding Ontario's future electricity supply.

I strongly support putting the highest priority on conservation. Well over half our current electricity use makes little or no contribution to human well being. Reducing demand should be the highest priority.

The second priority should be to convert all fossil fuel operations to renewable energy sources as quickly as technically and fiscally possible. But this effort should be considered in light of the highest priority of conservation. Attempting to replace existing high and wasteful levels of electricity with renewables will only solve part of the energy and environmental problems we face. Reduction in demand, with a priority given to ensuring human well being is protected, should be the overriding priority. The reasons behind this proposal may be found in the Energy section of www.sustainablescale.org.

Sincerely

Jack Santa Barbara
The Sustainable Scale Project
Lynden, ON

The power mix should madate that photovoltaic, wind, fuel cell, heat pump and hydro electric be major components of the mix. In addition, every effort should be made to design out the need for any large energy requirements.New Buildings should be constructed to minimize the need for air conditioning and electric heat. Waste heat from generation should be used to heat homes instead of being dumped to our environment.
Owners of older buildings should be encouraged to install energy efficient appliances and increase insulation with energy unit rebates. Unless absolutley necessary, all maintenance on generating systems must be done when demand will be lowest.

Gord Taylor

To Whom it May Concern:

Please consider the following when contemplating the future electrical needs for the province of Ontario.

Yesterday there was some discussion on the local radio about Ontario becoming a have not province. When it comes to electricity, I think we already are.

It used to be that the electrical focus in Ontario was to provide electricity to the citizens at the lowest possible cost. This meant affordable, competitively priced electricity for it's businesses and people. However, today's market focus seems to be based on financial values alone. This has shifted the focus from building a robust electrical system to how can I make the most money. Short term thinking will result in long term pain!

As you well know, electricity, unlike most other commodities can not be stored for future use, hence one must build sufficient facilities to produce AND transport it where and when it is required. This is not to say that we should simply build facilities at will - far from it. We must educate citizens on the real costs of electricity and show them ways they can impact those costs. However, to think that you are going to be able to stop increasing demand through residential programs is irresponsible. A big hit will NOT be through conservation programs aimed at residential consumers but through tougher building standards, not only in our physical structures, but in the equipment that goes into them. For example, why do we allow less efficient appliances (i.e.. fridges, air conditioners, etc.) to be sold? Surely the manufacturers would save money by not having to engineer and stock less efficient compressor systems, etc. Mandate tough efficiency standards. That being said, mandating "smart meters" for everyone will not reduce the consumption of electricity enough to pay for the initiative and have very little impact on the demand (and it's the reduced demand that we need to control). Economically, this initiative is flawed These meters are simply another tool in the kit that should be used wisely.

Ontario should be self sufficient for electricity supply.
This INCLUDES the use of clean coal technologies, renewable resource based technologies and nuclear. Shutting down coal fired generating stations simply because they are coal fired is also irresponsible. There are technologies that are as clean, if not cleaner, than natural gas fired units. What price are we willing to pay for these new gas fired generation when the gas supplies become even tighter? Diverse energy sources are required to provide reliable, affordable supply.....and since we are going to need a whole lot of generation within the next decade (if we continue to exclude coal fired stations from our portfolio), we better announce the site for the next nuclear station soon.
Electicity from wind should be part of the mix, but it should not be regarded as the saviour. With a 30% utilization factor at best, it's not something you or I will be able to count on on the hottest day of the summer or the coldest day in the winter.

Electrical distribution needs to be consolidated. What's with all these LDCs? Wouldn't the structures of Manitoba, BC, Saskatchewan and Quebec be much easier to manage and regulate (and the people might be able to understand who there supplier is too)?

Thanks for taking the time to read my input.

J. Taylor
Tecumseh

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July 8, 2005

Mr. Neil Freeman
Director, Planning Policy and Approvals
Power System Planning, Ontario Power Authority

Re: RFP wrt OPA's Advice to the Minister on Supply Mix

Dear Mr. Freeman

I have reviewed the subject RFP and offer that this analysis will be most welcome in this region. This City and the region in general are suffering a continuous slow depopulation in face of a number of issues, among them the uncompetitive cost of electrical energy for the region's high value added forest products/ pulp and paper industry. Together with wood fibre, skilled labour using sophisticated technology, electrical energy itself is the third major ingredient added to produce this value. Recently political announcements and events have driven concerns to extreme levels prompting an unprecedented alliance of industry, business, civic and labour groups to bring this matter most forcefully before various Provincial authorities. The overall effect of Ontario's current direction on regional investment confidence is very, very troubling.

It is with sadness as well that we have seen that the region is viewed in a "third world" light by the Cabinet and the best responses to date have been in the form of such things as offers of loan guarantees which are at best insulting to serious investors in the regional economy. The concerns have also been met with nonsensical announcements such as conversion of local lignite burning generating facilities to natural gas and trivialized by offers of "value added studies" to offset what without real change in direction will certainly be the loss of multi-billion dollar investments and similar local cash flows.

We must urge you in execution of the RFP and in making your recommendations that the west system and the associated regional economy be fully taken into account. This would need to include system administration as well as generating plants and fuel alternatives. The bottom line is just that – the bottom line, and I must reiterate that this area in Ontario has become very much a non-competitive jurisdiction. Our own efforts are directed to attempting to stop the migration of our major industrial base to other Canadian and U.S. locations. At the moment we are attempting to get signals out that will delay very damaging and non-reversible investment decisions at least pending the results of current efforts at regaining regional competitiveness. Your actions can significantly, positively or negatively, impact this matter.

We will be pleased to work with your designated consultants but must urge inclusion of true electrical energy cost competitiveness for this region in your deliberations.

Yours truly,

Bruce Hansen
Thunder Bay Economic Development Department (Forestry/ Pulp and Paper/ Energy)

Greetings!
No matter where Ontarians get their power from, a major factor will be cost.
Although green and renewable energy sources are ecologically sound, are infinitely abundant, and can supply the majority of our energy needs*, a major voice in the opposition will shout loud and clear: "COST!!"

Cost is an issue. But there are too many hidden costs in non-renewable sources to ignore. Nuclear power is clean and cheap until you consider the longterm costs of containing dangerous used fuel and of fixing aging facilities. Health care costs skyrocket with poor air quality from burning coal. Canadians die prematurely from poor air quality. That is a cost.

The cost differences between traditional nuclear or other non-renewable energy sources versus renewables is literally tenths of a cent per kWh. The health-care costs, the lost productivity due to air-related illness, and the loss of life add up to much more than tenths of a cent.

There should be open debate so we can finally close it. The decision for an economically viable, socially responsible, and environmentally friendly energy supply is one of the most important decisions to make.

I see a distant future in which 100% of our energy needs come from renewable sources. The only costs will be for facility and infrastructure maintenance.
For now, over 50% is attainable*. For now, there is a decision to be made.

All the best,
Sincerely,
~ David Toms
* please see: www.cleanairalliance.org/resource/15month.pdf

The Toronto
Board of Trade

September 30, 2005

Mr. Amir Shalaby
Vice President, Power System Planning
Ontario Power Authority
175 Bloor Street East
North Tower, Suite 606
Toronto, ON M4W 3R8

Dear Mr. Shalaby:

Re: Ontario's Electricity Supply Mix

Thank you for the opportunity to provide input to the Ontario Power Authority (OPA) as you set out to develop recommendations to the Minister of Energy, Dwight Duncan, on Ontario's supply mix. The Toronto Board of Trade believes that an adequate, reliable and affordable supply of electricity is critical to maintaining and strengthening Ontario's economic future. Ontario's current supply challenges can only be resolved through a range of initiatives, including the introduction of smart meters, enhanced conservation efforts and the use of a diverse range of fuel sources and technologies.

We believe the OPA's recommendations to the provincial government on this issue will play a pivotal role in the direction Ontario will take to address its current electricity supply challenges. Our comments on this vital issue for our province are set out below:

Key Goal

The Toronto Board of Trade believes that Ontario's goal must be to develop an adequate, reliable and affordable supply of electricity to maintain and enhance the strength of our economy and the competitiveness of our businesses. We believe this overall goal must be kept in mind in any recommendations that the OPA develops for the provincial government.

Rising Demand

Every forecast shows that demand for electricity is rising and will continue to do so for the foreseeable future. In July 2005, demand for electricity hit a peak of 26,160 MW. This past summer, the Independent Electricity System Operator (IESO) issued twelve public appeals for demand reduction and implemented two voltage reductions to maintain system integrity. Conservation efforts, although very important, will only go so far in slowing future demand. As a result, developing an adequate supply of electricity is critical to the province's economic and social growth.

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The Toronto Board of Trade

Limited New Supply

Ontario has added approximately 2,500 MW of generation over the past two years. However, we note that despite the return to service of units at Pickering and Bruce and new capacity though the Brighton Beach plant, we continue to need more generation to meet demand. At the same time, the province's operating nuclear plants are old and will gradually be retired over the next 15 years. This situation is exacerbated by the province's policy to remove coal plants from the generation mix that will reduce our supply and drive electricity prices higher.

Diversity of Sources is Critical

To meet Ontario's future needs for reliable, adequate and affordable electricity, we need supply from a diverse mix of sources. The solutions require the inclusion of all technologies and the participation of all stakeholders—government, local distribution companies, the private sector, the IESO and customers. It is unrealistic to assume that Ontario's future needs can be adequately met by one or two primary fuel sources. There is no single source that can provide Ontario with an adequate, reliable and affordable supply of electricity. Each source has its unique mix of characteristics that make it best suited for a specific role within the overall supply mix. There is an expression "horses for courses" which denotes that different breeds of horses are suited to different racecourses. In Ontario, one might say our generation mix could be likened to the following:

- **Work horses:** Base load (runs for more than 60% of the hours in a year, e.g., nuclear, large hydro)
- **Quarter Horses:** Intermediate (15 to 60%, e.g., coal, large combined cycle gas turbines)
- **Race Horses:** Peaking (less than 15%, e.g., simple cycle gas, storable hydro)
- **Relief Riders:** (for economic or environmental benefits, intermittent renewables, other sources)

A diverse range of supply to meet our various needs must similarly mark Ontario's electricity supply.

All Hands on Deck – including Coal-Fired and Nuclear Generation

Clean Coal

The Toronto Board of Trade believes diversity of supply is crucial to a healthy business climate and quality of life. We need to keep the capabilities of the various technologies and fuels in mind as we develop our energy policy before we consider eliminating any

.../3

technology or fuel from our supply mix. That is why we do not believe Ontario should summarily rule out a future role for coal-generated power. As noted by David Goulding, President of the IESO, in his remarks at the OEA conference (September 14, 2005), coal-fired plants continue to have numerous system reliability advantages such as:

- on site fuel inventory/availability;
- load following capability;
- ability to perform deep manoeuvres while staying on line; and
- ability to provide automatic generation control and dynamic voltage control.

In addition, we note that the current electricity network was designed to accommodate the location of coal-fired stations. If the electricity flow and short-circuit levels are changed to accommodate different generators with different operating regimes, costly changes will be required to Ontario's electricity grid.

We recognize the importance of clean air and environmental concerns and note that there have been significant advancements in technology that make coal a much cleaner fuel source than ever before. For example, Genesee 3 (G3) in Alberta is the most advanced coal generation plant in Canada and the first of its kind in North America. The plant is a joint venture between TransAlta and Edmonton-owned EPCOR, has the ability to generate 450 MW and meet provincial environmental standards. The supercritical boiler technology uses higher temperatures and steam pressures rather than traditional coal-fuelled boilers, which means using less coal to produce the same amount of power (about 11%). The nitrous dioxide at the plant is half of existing coal-fired plants, carbon dioxide emissions is 18% below the average Alberta coal plant, and there is a release of only 0.1% particulates into the air. The sulphur dioxide emissions are 57% below provincial limits. And clean coal technology continues to improve every day. This model illustrates that coal-fired generation could continue to play a useful role in Ontario.

Nuclear

Last month, Premier McGuinty said that "should the OPA recommend nuclear as being an indispensable part of a diverse supply of electricity, then we will build new nuclear in this province." The Toronto Board of Trade believes that nuclear power has served Ontario well in the past and has the potential to continue playing an important part in Ontario's electricity supply mix. While there have been cost overruns and delays associated with our nuclear plants, other jurisdictions have demonstrated that with good management and controls, this can be avoided. With Canada's ample supply of natural uranium, nuclear reactors can provide competitively priced electricity for Ontario's base load and high tech jobs for Ontarians. Nuclear waste is a challenge that can be managed using technological advances made to date. We also believe that Ontario should consider risk sharing by working with the commercial sector (e.g., AECL or private developers).

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Transmission Interconnections
The Toronto Board of Trade believes that strengthening and increasing our interconnections with neighbouring jurisdictions will help build system support, allow for the freer flow of power to meet demand fluctuations and improve system reliability across the Northeast region.

New Supply Technologies
The Toronto Board of Trade believes that three additional areas of supply must be seriously considered for Ontario's supply mix.

Gas Generation
The province has selected a number of projects via its Request for Proposals, the majority of which are based on gas-fired generation. Gas generation offers greater flexibility and due to shorter construction timeframes, is better able to meet Ontario's shorter-term needs, albeit at a higher cost than coal-fired generation.

Renewable Generation
We also believe the province should support renewable generation technologies such as wind, solar, biomass and run-of-the-river generation. By reducing overall reliance on any one source, these technologies offer greater flexibility and provide more options for Ontario's supply mix. They can also play a useful role in helping Ontario meet Kyoto requirements.

Cogeneration and Micro-turbine Technology
Including customers and private businesses in the supply mix is important. Cogeneration and generation from technologies like micro-turbines placed close to customer demand will meet the generation challenge at the source.

Immediate Action is Required

For many decades, Ontario's inexpensive and reliable supply of electricity has been a key draw for many energy-intensive businesses, such as mining and auto manufacturing, to locate and expand in our province. Ontario's advantage in this area is quickly eroding and, based on the gap between demand and supply forecasts, is quickly becoming a disincentive to investment. Ontario must move quickly and decisively to restore the confidence of business and residential electricity consumers in our electricity system.

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The Toronto
Board of Trade

The Toronto Board of Trade cares strongly about the continuing economic prosperity of Ontario and supports a generation mix that ensures system reliability, enhances security of supply and at the same time offers competitively priced electricity that complies with legislated environmental standards.

We would be pleased to address any questions you may have or elaborate on our comments.

Sincerely,

Bob Hutchison
Chair

Glen E. Grunwald
President & CEO

Toward a Sustainable Future for Ontario's Electricity System:

Submission to the Ontario Power Authority from the Toronto Environmental Alliance on the proposed 'system mix' in Ontario

By Keith Stewart, Ph.D.[1]

> "To survive in the world we have transformed, we must learn to think in a new way. As never before, the future of each depends on the good of all."
> - Statement of 100 Nobel Laureates on climate change and global peace (Oslo, December 2001)

It has become a political truism in Ontario to say that our electricity system stands at a crossroads. Over the next fifteen years, Ontario's electricity system will be largely re-built in what the province's Minister of Energy has called "one of the largest peace-time investments in Canadian history."[2]

The choice of the energy path we will follow is not a purely technical or economic decision, for it will have profound political, social and ecological implications. The decisions we make in the next few years will shape our electricity system for the next generation and this historical moment represents an opportunity to rebuild our electricity system along more sustainable lines.

When discussing energy policy, it has now become customary to include at least a cursory discussion of sustainability. Yet in the face of the long-term threats of climate change[3] and nuclear waste[4], and the more immediate threats of air pollution, potential nuclear accidents or the proliferation of nuclear weapons, it is no longer sufficient to relegate discussions of sustainable energy systems to some indefinite future or to environmental studies faculties.

This paper is a response from the Toronto Environmental Alliance to the Ontario Power Authority's request for input on what the new provincial 'system mix' should be (i.e. targets for how much electricity should come from what source). But it is our contention that this is the wrong question. *For no one wants electricity but rather they want the services it can supply – and we can meet these needs using half of the electricity currently being transmitted over the grid*.

We begin by addressing the implications of the commitment to phase out coal-fired electricity in Ontario and the assumptions which have guided past system planning in the province with an eye to avoiding the mistakes of the past. We then turn to defining what a 'sustainable' electricity system would look like and identifying the principles that would guide planning for a transition to such a system. These principles are then transformed into specific targets and policy measures that could be adopted to help make this transition, drawing on the analysis put forward in the *Power for the Future: Towards a Sustainable Electricity System for Ontario* report that was released by the Pembina Institute for Appropriate Development and the Canadian Environmental Law Association in 2004 as well as complementary reports from the Campaign for Nuclear Phase-out and the David Suzuki Foundation.

Yet the crucial first step is to recognize that we need to start planning how to build a different type of energy regime, not incrementally shift the generation mix of the current electricity system. Informing our overall approach is the work of historian David Nye, who rejects technological determinism and a simple equivalence between rising energy consumption and cultural advance, while recognizing that the choices we have made in the past ensnare us within power systems that are not easily changed. The attempt to get to what Nye calls a "sixth energy system" emphasizing renewable power sources and "an

eclectic bricolage of many technologies and conservation measures" will no doubt be constrained by "the myriad choices Americans [and Canadians] have made – choices expressed in factories, roads, cities and suburbs." [5]

Yet those trying to overcome these constraints can at least take heart from Nye's review of the historical record, which shows that those who experienced the past energy systems at their height didn't forsee the speed with which these systems could lose momentum and be overtaken by a different set of technologies, social processes and cultural attitudes.

To achieve a sustainable electricity system, we will need to re-think assumptions regarding the relationship between electricity consumption, economic growth and quality of life. We will also have to re-think the traditional 'hub-and-spoke' model of large, centralized generators delivering power to distant users over a network of high-voltage transmission lines. The system of the future will look less like a nuclear or coal plant with high-voltage transmission lines marching across the countryside to passive consumers, and more like a 1000 points of (highly energy efficient) lights.

A starting point is Walt Patterson's insight that much conventional thinking about electrical systems – and particularly recent attempts to privatize systems and create markets in electricity - makes the mistake of treating electricity as a commodity or a fuel.[6] Yet electricity itself serves no purpose. Nor can it be stored for later use like most commodities. Electricity must (like ecological systems) be understood as a process – a flow of electrons that we can direct to achieve a remarkable variety of objectives such as comfort, illumination, motive power and information handling by activating appropriate technologies.

Recognizing this difference, Patterson argues, will lead to a shift in emphasis from fuel-based electricity such as coal or nuclear power that delivers power to customers over a one-way network, to what he calls 'infrastructure' energy, i.e. small-scale, decentralized power sources that rely on flows of (renewable) energy and use this energy within highly efficient 'activating' technologies to delivered the desired services locally.

The consequence of understanding electricity this way is that it requires that we reject attempts to plan a system to deliver electricity independently of planning how it will be used (or not used, as electricity is replaced by solar or geothermal energy that can better meet the need for heat, light or cooling power). It requires us to begin by asking what energy services (light, comfortable homes and offices, motive power and information handling) we want, and what is the best way to deliver them. For by starting from what we want and how to get it, rather than how to generate and transmit a given amount of electricity, we will come to very different conclusions on what the electricity system of the future will look at.

> What we call 'energy policy' is still really 'fuel and power policy', preoccupied with batch transactions in commercial energy carriers treated as commodities and priced by the unit…. 'Energy policy' that concentrates entirely on the availability and cost per unit of commercial energy carriers misses the most important part of human energy systems: the energy service systems, especially buildings and their fittings.
>
> Real energy policy should be far wider in scope than fuel and power policy. Real energy policy should encompass all aspects of energy investment – not just in facilities to produce and deliver commercial energy carriers [e.g. electricity generators], but more importantly in facilities to deliver the energy services people actually want…. Electricity, with its distinctive attributes and its applicability to integrated local systems, could mediate the transition to real energy policy….
>
> We must, however, get there from here, around the world, while minimizing disruption and keeping the lights on…. The prize could be a sustainable planet; but the task is awesome and

> daunting. It will demand technical flair, financial acumen and political courage. Can we meet the electric challenge?[7]

Meeting this challenge won't be easy, but this paper attempts to set us on the path and identify how we can start moving Ontario in the right direction.

The System Mix and the Coal Phase-out

When it comes to planning the future electricity system, this is an interesting moment globally because the energy system is facing new possibilities and challenges, while new options are emerging in electricity generation and networking. Yet it is a particularly interesting moment in Ontario because the provincial government has – in response to a sustained campaign by environmentalists and public health advocates[8] – committed itself to phasing out coal-fired electricity in Ontario. While this was to originally have been achieved by 2007, it has now been revised to 2009.

As a first step towards a more sustainable electricity system, phasing out coal could be a significant environmental victory. According to the most recent data available, Ontario's coal plants produced 18 percent of the province's greenhouse gas emissions,[9] as well as 15% of smog-causing nitrogen oxides, 23% of smog- & acid rain-causing sulphur dioxide, and 23% of mercury emissions.[10] They are also a major source of over two dozen other toxic and carcinogenic compounds such as lead, cadmium and chromium.

Yet how much of an environmental victory depends on how these coal plants are replaced. The principal options the government has considered for achieving this phase-out are:

1. a nuclear renaissance (i.e. the refurbishment of reactors at the Pickering A and Bruce A plants closed in 1997 due to safety concerns, as well as the construction of new nuclear plants);
2. the construction of natural gas-fired generating stations; and
3. a combination of nuclear refurbishment and new gas-fired stations (which appears to be the the preferred option).[11]

Nuclear power has, of course, long been opposed by environmentalists as risky, expensive, environmentally damaging and linked to militarism / nuclear weapons. Refurbishment of reactors mothballed in 1997 due to safety concerns has been overdue and over-budget (the first reactor re-started at the Pickering A station was over two year late and cost 50% more than the original estimate for re-starting all four reactors).[12] At the time of writing, the provincially-owned utility Ontario Power Generation has announced that it will not attempt to re-start the remaining two reactors at the Pickering Station, but the government is negotiating with the private firm that operates the Bruce Nuclear Station regarding re-starting two more reactors there.

Natural gas has been more acceptable to environmentalists. It burns much cleaner than coal, emitting 90% fewer smog-causing nitrogen oxides and up to 60% fewer greenhouse gases per kilowatt hour, while virtually eliminating sulphur dioxide, mercury and the carcinogens found in coal. Nevertheless, natural gas does pollute and it is non-renewable (with North American supplies becoming increasingly scarce and more expensive) – which is why most environmentalists have argued for the efficient use of natural gas as a transitional fuel, in the shift to a system built around conservation and renewables. As this paper is written, the McGuinty government is in the process of contracting for over 5000 megawatts

of new natural gas-fired generation, which would increase gas share from 7 percent of overall generation to over 20 percent of supply.

Yet the desired 'green alternatives' of energy conservation and renewable sources of energy such as wind, micro-hydro and solar power are according a minor role in the province's energy future according to the government's plan.

Conservation – the most important element in a sustainable electricity system for environmentalists – is envisioned as only being capable of slowing the rate of growth in demand for electricity. This can be seen in the watering down of the government's 2003 election platform commitment to reduce energy consumption by 5% by 2007, which has been re-interpreted as a reduction in peak demand (rather than overall consumption) of 5% relative to an anticipated annual growth rate of 1.7% (peak demand and total consumption can rise while the 'conservation' target is met).

What was remarkable in the government-commissioned study cost-benefit analysis of cleaning up or replacing the coal plants was that it didn't even include energy conservation as an option, in spite of the existence of some fairly sophisticated economic modeling of conservation's potential and costs in Ontario using the Canadian Integrated Modeling System developed by Simon Fraser University[13] that was incorporated into the Pembina/CELA report *Power for the Future.*

The McGuinty government has established renewable energy targets of 5% of installed capacity by 2007 and 10% by 2010, although given the low capacity factor of most renewable technologies (e.g. 30% for wind power) these would likely only produce 2 – 6% of overall supply.

The challenge, according to reports such as that of the government-appointed Electricity Conservation and Supply Task Force, is to meet the rapidly rising peak demand of 1.7% per year over the 1994 – 2003 period.[14] It is important, however, to note that the Task Force - established by the Conservative government of Ernie Eves in June 2003 but reporting to the Liberal government of Dalton McGuinty in January 2004 – was dominated by energy generators and distributors whose economic self-interest lies in selling more electricity, while other major players represented large industrial consumers and the industry coalition that has been advocating privatization. There were no environmental groups on the Task Force, and even the Canadian Energy Efficiency Alliance representative was from a manufacturer of electrical generators.

The Task Force was, moreover, very selective in its use of data to establish a rapidly-rising trend. By choosing the 1994 – 2003 period for establishing trends, they disguised the fact that peak demand dropped from 23,630 MW in 1989 to 21,000 in their base year of 1994. The 1989 – 2004 increase in peak demand, on the other hands was less than 0.5% per year, or one-third the rate claimed by the Task Force, with a 'reasonable' trend line probably being somewhere between the two.

The report also stated that aggressive conservation might be able to slow the growth in demand to 0.5% (again using selective use of data to disguise the fact that overall consumption rose only 0.7% per year in the 1989 – 2003 period) and implied that while renewable energy might serve as green window-dressing, Ontario would need new nuclear plants to keep the lights on.

This is significant, because without questioning some of the assumptions underlying growth estimates, Ontario risks repeating mistakes of the past in over-estimating future demand

and underplaying the potential role of energy efficiency improvements – and renewable energy – in the future system mix.

The Perils of Forecasting: Learning from Past Mistakes

The OPA is being asked to look 20 years into the future and has recognized the "considerable uncertainties in long-term resource planning."[15] Yet it is not simply "uncertainties" that need to be taken into account, but the underlying assumptions that will guide decisions on the system mix.[16]

The significance of these underlying (and unstated) assumptions in system mix planning debates in the 1970s and early 1980s has been concisely summarized by Paul McKay:

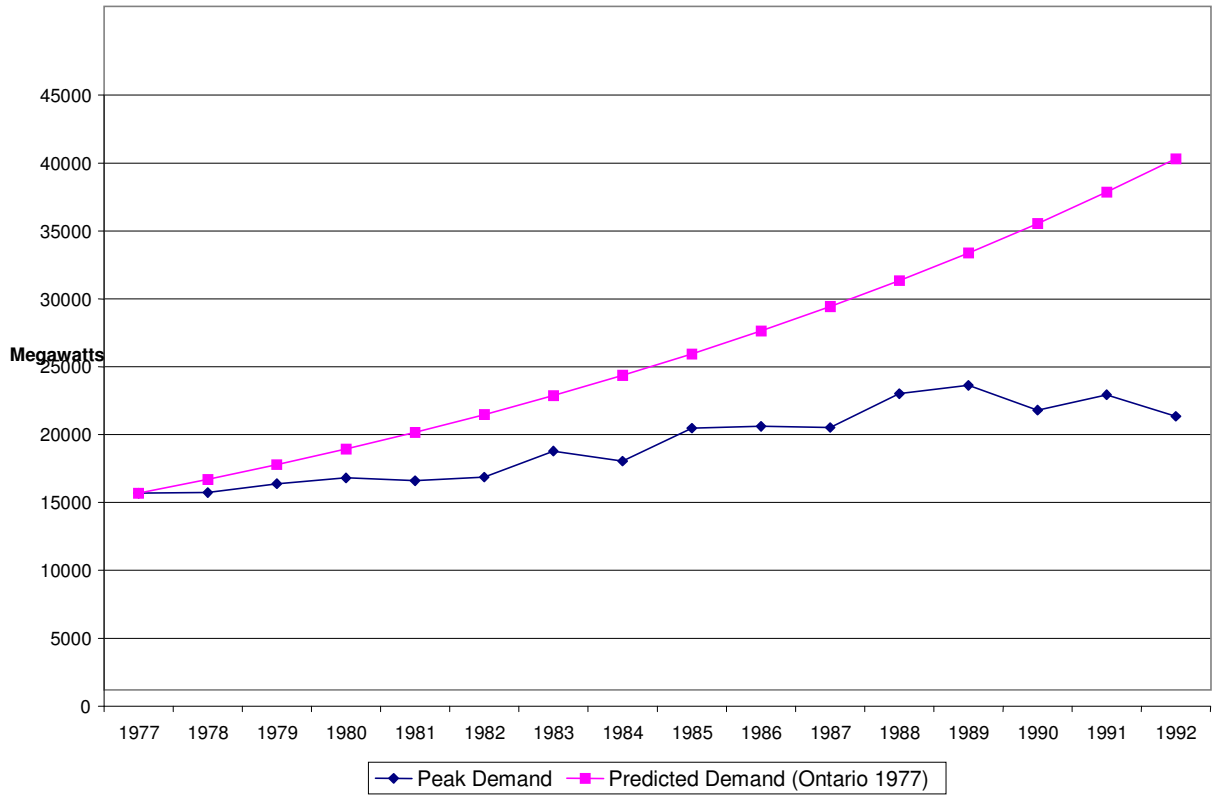
> In each case [the 1978 Porter Commission, the 1979 report of the Select Committee on Ontario Hydro Affairs, and the Ontario Ministry of Energy], their forecasts preceded and undercut Hydro's by thousands of megawatts, because they started by recognizing, unlike Hydro, that exponential energy growth was not an end in itself, that it had enormous economic and environmental consequences, that conservation and energy efficiency might prove a cheaper, quicker solution to the energy crisis than creating new sources and, finally, that energy consumption patterns were changing in relation to the changing needs and values of society.
>
> Thus it was not complexity that compelled Hydro to make the chronic forecasting errors it made during the 1970s, but the assumptions behind these forecasts and the institutional inability to accept change.
>
> In the end, Hydro became caught in its own internal logic: extrapolating traditional exponential demand into the future led to the commitment of ever-larger energy centres, which intrinsically demanded ever-longer construction lead times. These in turn both increased Hydro's need to predict accurately further into the future and decreased its technical ability to change course once the decision has been taken.[17]

This stands in stark contrast to the sustainable approach which sees energy as a means of meeting limited needs for comfort, illumination, transportation, and the safe preparation and storage of food. To meet these needs in the current context of the massive waste of energy, the first priority must be energy conservation – understood as both conservation (doing less) and increasing energy efficiency (doing more with the same amount of energy).

Lest such priorities be dismissed as tree-hugger fantasies, it is worth noting that Ontario's environmental movement has a better record of predicting future demand than old-style system planners over the last 30 years. In the debates before the Porter Commission in the late 1970s, environmentalists argued that Ontario Hydro's 1977 predictions of a 6.5% annual growth rate was far too high and that growth would be closer to 2% per year.[18]

As shown in Figure 1 (below), the increase predicted by Ontario Hydro after 15 years was over 4 times higher than the actual increase – and the situation becomes exponentially worse if you extend it to 20 or 25 years. The difference between predicted and actual peak demand over 15 years was the equivalent of 5 Darlington-sized generating stations.

Figure 1: Actual versus Predicted Peak Demand in Ontario, 1977 – 1992 (Source: Ontario Hydro Annual Reports and Ontario Hydro Statistical Yearbooks)

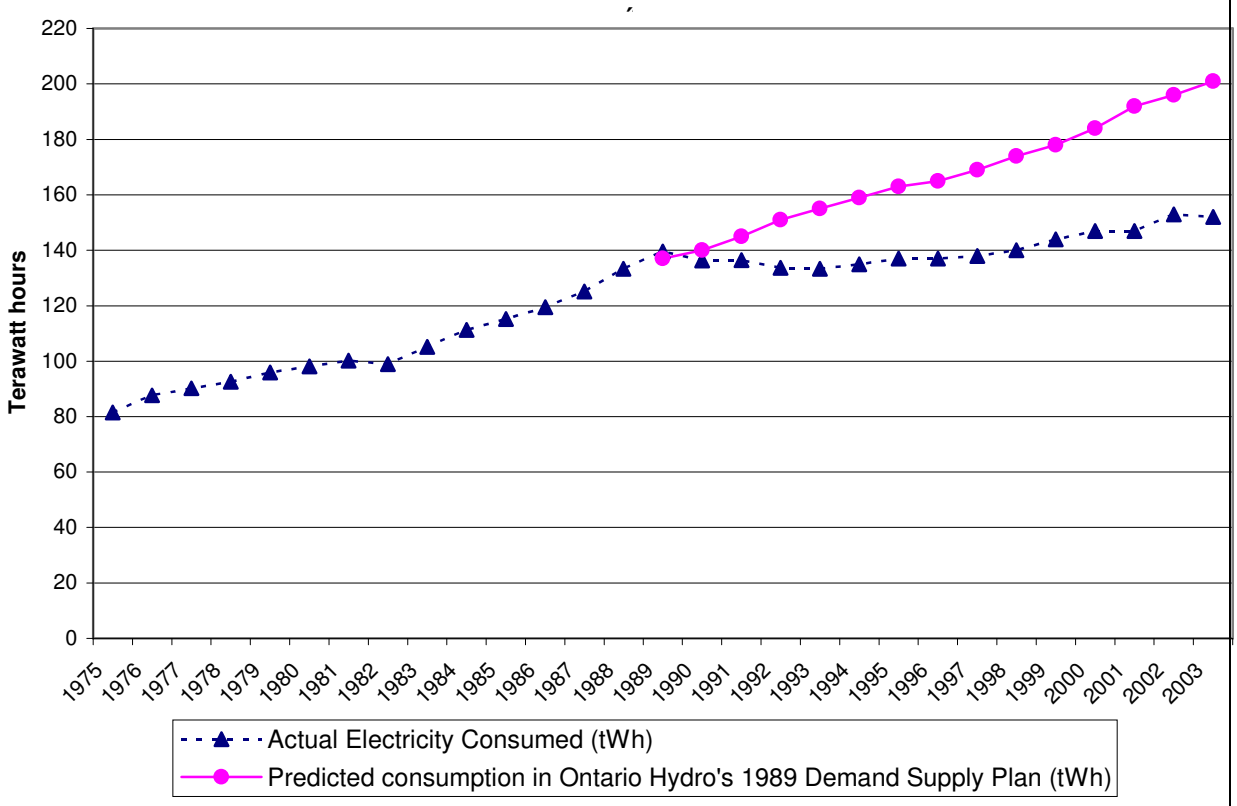


Yet this systematic over-estimation of demand growth is not simply an artifact of the 1970s. The last time that system mix planning was attempted in Ontario was in the late 1980s, when a 25 year Demand Supply Plan was developed by Ontario Hydro, summarized in the 1989 document *Providing the Balance of Power: Ontario Hydro's Plan to Serve Customers' Electricity Needs*.

Ontario Hydro's system planners assumed that future demand – even with $300 million per year invested in conservation - would be a linear projection of the past (see Figure 2). They also estimated that, in their most likely scenario, the province would need the equivalent of 2 new Darlington-sized nuclear stations to generate 7,100 MW of power and 32 fossil fuel-fired turbines capable of generating 4,300 MW by 2014.

In reality, demand fell in the early 1990s and has grown at about 0.7% per year in the 1989 to 2003 period, which is below the rate of population growth in Ontario. This drop in demand growth was truly fortunate, for eight nuclear reactors with over 5,000 MW of capacity (i.e. more than the 3,600 MW added by the completion of the Darlington nuclear station) were closed due to maintenance, safety and management concerns between 1995 and 1997. And an ill-fated move toward electricity privatization resulted in no significant new generation coming on-line in Ontario in the 1994 – 2003 period, while what few conservation programs that existed were eliminated; then-Energy Minister Jim Wilson explained the change in policy by saying "The private sector asked us to get out of large-scale government conservation programs. [They] may have made the odd person feel good, but they had absolutely no effect." [19]

Figure 2: Actual consumption vs. the predicted electricity consumption in Ontario Hydro's 1989 Demand-Supply Plan (Sources: Ontario Hydro (1989) and Ontario Energy Board (2005))



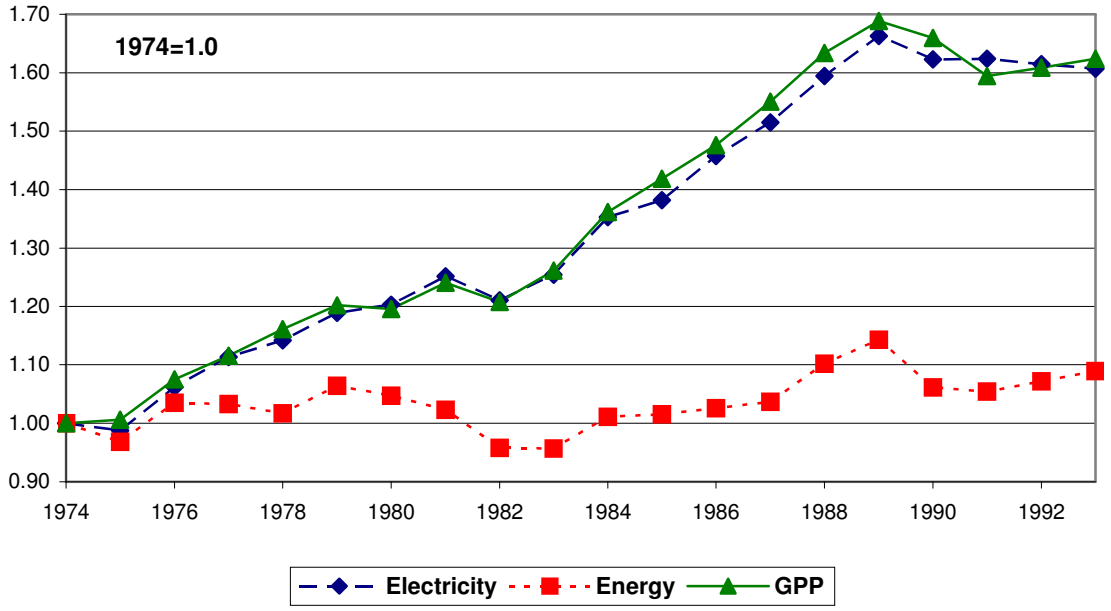
So with a net decrease in generating capacity in the 1994 – 2003 period, why didn't the lights go out?

One factor was the recession of the early 1990s which reduced demand for electricity. Yet in subsequent years, economic output grew rapidly while electricity consumption continued to decline on a per-capita basis.

A more convincing explanation has been offered by energy expert Ralph Torrie, who argues that electricity consumption has become de-coupled from economic growth.[20] From 1958 to 1974, the output of the Ontario economy grew at an average rate of 5% per year while electricity consumption grew at 6.8% per year. This rapid growth was due to the expansion of end-uses for electricity (new appliances, increasingly mechanized manufacturing, etc.) and as electricity took some market share from space and water heating (largely as a consequence of 'Live Better Electrically' promotional programs by Ontario Hydro and the provincial government to build load).

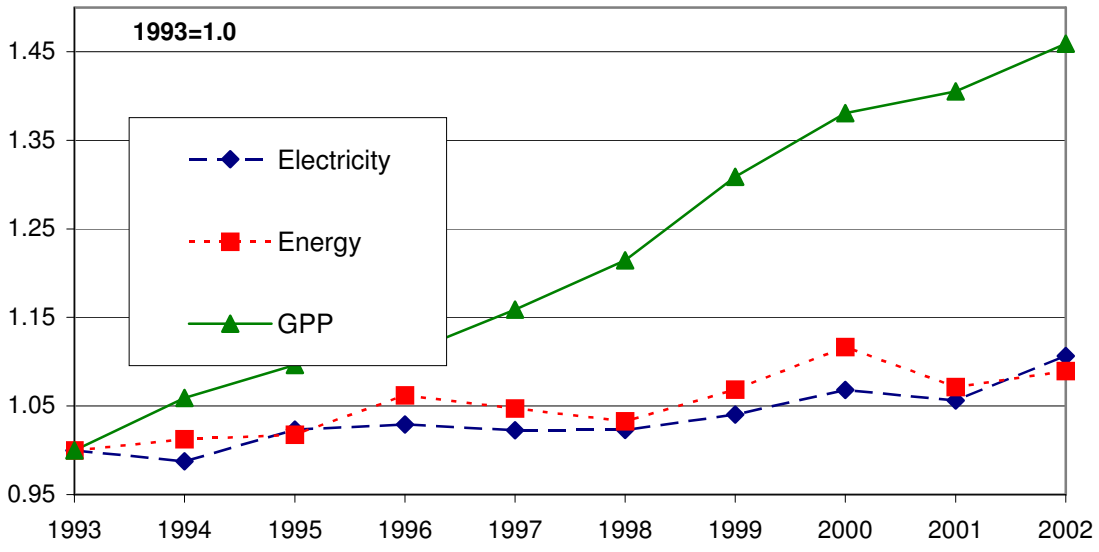
Yet as end-use market became saturated, this growth rate tapered off and began to match economic growth rates. As shown in Figure 3, electricity consumption closely followed economic growth in the 1974 – 1993 period, although overall energy consumption was dropping relative to growth as oil consumption became more efficient in response to the oil shocks.

Figure 3: Electricity, Energy and Economic Growth (Gross Provincial Product) in Ontario, 1974 – 1993 (Source: Torrie, 2004)



Yet in the 1990s, the growth in electricity consumption slowed, and even fell in per-capita terms (see Figure 4 below). Even starting from the recession-induced low of 1993, electricity consumption has been growing at only 1.1% per year (0.7% if you start from 1989) while economic growth has averaged 4.3% per year.

Figure 4: Electricity, Energy and Economic Growth (Gross Provincial Product), 1993 – 2002 (Source: Torrie 2004)



This reduction in demand growth may have been influenced by the energy efficiency programs introduced by the Peterson and Rae governments in the 1988 – 1994 period, but even these modest initiatives were dismantled by the Conservative government of Mike Harris in the latter half of the 1990s.

The primary factors, according to Torrie, for the 'decoupling' of electricity consumption from economic growth are:

1. Structural changes in the economy which reduced the relative role of energy-intensive extractive and manufacturing industry.
2. Capital stock turnover resulting in more energy efficient equipment replacing older, less efficient lights, pumps, appliances, etc.

Remarkably, this transition to a less electricity intensive economy (Gross Provincial Product per kilowatt hour in Ontario rose from $2.30/kWh in 1991 to $3.12 per kWh in 2002, expressed as 1997 dollars) occurred largely in the absence of any concerted attempt on the part of the government to foster this change.[21]

Which raises the question: *What could we do if we really tried to reduce electricity consumption?*

Or to use Patterson's words, can we marshal the technical flair, financial acumen and political courage to get there from here to there (a sustainable electricity system) while minimizing disruption and keeping the lights on?

What is a Sustainable Electricity System?

Sustainability, and its parent term Sustainable Development, are two of the most politically flexible terms of our time. As they can mean just about anything and be mobilized to serve just about anyone's purposes, it is important to be clear on how they are being used here.

For the purposes of this paper, a sustainable energy system is one that meets people's need for energy services – comfort, illumination, transportation and the safe preparation and storage of food – in an equitable manner that relies on *flows* of low-impact renewable energy (ultimately either geothermal energy or the sun, although the sun's energy can be transformed into wind, hydro and bio-mass energy), rather than on consuming the '*capital*' of energy stocks in the form of fossil fuels or nuclear power.

The principles of such a system[22] would include:

1. To use the energy we truly need as efficiently as possible, while living within democratically-determined social and ecological limits (for example, commitments under the UN Framework Convention on Climate Change to stabilize greenhouse gas concentrations at levels that will prevent dangerous interference with the climate system).
2. To get this energy from sources that are:
   - renewable;
   - diverse;
   - smaller-scale and more decentralized than the contemporary hub-and-spoke system made up of large power plants transmitting power over long distances;

- relatively simple and understandable from the user's point of view, but can still be technically sophisticated (what is often referred to as elegant simplicity); and
- used to do what they do best, i.e. supply energy in the right scale and the right quality for our range of end-use needs. This would result in some current uses of electricity, such as for space or water heating, being replaced with solar thermal or other technologies.

3. The intelligent use of fossil fuels (such as cleaner-burning natural gas) for the transition.
4. To ensure equitable access to adequate, safe energy and conservation services as a basic necessity so that even as prices rise, the poor aren't left to freeze in the dark.[23]

To get an idea of what such a system might look like, it is worth citing Walt Patterson at length:

> Using only technology that already works, but that may at the moment be considered too costly, can you devise a system in which all electricity services now required are provided with a maximum of reliability and a minimum of environmental impact? Remember that what we want is the services - illumination, comfort, motive power, refrigeration, information handling and so on - not the electricity. If we can get the same or better services more reliably with less electricity, fine.
>
> A high-reliability, low-impact system might look something like this. All buildings are designed and constructed to take maximum advantage of natural ambient energy flows, including light, heat, and convection currents of air. Daylight reaches much of the interior of a building. The building structure acts as a heat store, soaking up excess heat or releasing stored heat, to keep the interior at a comfortable temperature whatever the temperature outside. Air circulates throughout the building gently and continuously, because of its interior layout and the small temperature differences between various parts of the building. A rapidly growing number of modern buildings in many parts of the world are already based on these principles - as, indeed, are many very old buildings, constructed before electricity became an option, when builders made skilled and subtle practical use of the light, heat and air circulation naturally available.
>
> Since the building itself provides much of the illumination and comfort required, electricity has much less to do to augment these services. The interior illumination comes from high-efficiency lighting, including compact fluorescent lamps for all lights that are on more than briefly, or are in awkward locations in which burned-out incandescents would need frequent replacement. Well-designed fittings direct the light to where it is wanted, with minimum waste. In temperate and tropical climates, buildings appropriately designed and constructed can maintain comfortable interior temperatures with little or no assistance from electricity; a requirement for significant active air-conditioning is a symptom of a badly designed building.
>
> In cold climates, however, when outdoor winter temperatures are well below freezing, additional interior warmth is provided by microcogeneration or by electric heat pumps, already common for instance in Scandinavia. Buildings are also equipped with sensors that measure temperature, light levels, occupancy and other relevant information, and with controls that automatically adjust the comfort and illumination to the levels desired.
>
> Inside buildings, two further categories of electricity service are particularly important, motive power and information handling. Motive power is delivered by electric motors. They are the appropriate size, not oversized as is otherwise common, and equipped with variable-speed drives to maximize efficiency over most of their operating range. Furthermore the equipment they drive is also appropriately sized. Fans and pumps, for instance, are integrated into ducts and pipes laid out to minimize frictional and other losses. The fans and pumps can therefore be smaller, and so can the motors to drive them. Improved system design, integrating and optimizing the performance of all components together, achieves better results at lower cost. The high-reliability low-impact system takes the principle of integrated wholesystem design as fundamental, for all buildings and process plant.
>
> Information, including communications, data-processing and entertainment, is handled by electronics. Telephones, faxes, computers, television, video, building controls and security

systems are all linked together by digital networks, not only within individual buildings but also across cities, countries and continents. Like electric motors, electronics are designed to optimize performance and minimize losses. One design feature is unexpectedly notable. The stand-by mode for electronic equipment, such as the red light that stays glowing on the television when you use the remote control to turn it off, is a surprisingly heavy user of electricity in modern society. In the high-reliability low-impact system, alternative design of standby modes reduces this insidious drain on electricity to a much lower level. Moreover, many people just turn things off completely when they are not in use.

Buildings, lighting, motors and electronics all contribute to delivering electricity services; but they still need electricity to run them. In the high-reliability low-impact system, much of this electricity is generated in or near the place it is used, minimizing vulnerability to disruption.

Buildings have gas engines, microturbines or fuel cells in the basement, fuelled by natural gas. Some of these units, and others using Stirling engines, operate in cogeneration mode, delivering both electricity and heat. Industrial sites needing heat also use cogeneration, sometimes including not only gas turbines but also steam turbines…. Some sites such as supermarkets that require heavy-duty refrigeration use not cogeneration but trigeneration, delivering not only electricity and heat but also ice-water for chillers. In suitable applications, trigeneration raises overall fuel efficiency yet higher.

Many buildings also have roofs and facades made of photovoltaic tiles. Buildings using fuel cells and photovoltaics have separate wiring to carry the direct current (DC) these generators produce, to power the electronics in the building. Electronic equipment always requires DC.

Delivering it directly avoids the losses involved in converting AC to DC and vice versa. Moreover DC does not carry the disturbances or 'spikes' common with AC, that can damage or destroy electronics. Delivering DC also eliminates the cost, weight and energy losses of the 'power pack' in the electronics, the transformer and other components to convert AC to the low-voltage DC the electronics actually require.

A local system of wiring and controls links on-site generation to the electrical equipment on the site. Local systems in turn are connected to a wider network that includes larger generators, notably large old hydro plants and modern microhydro units, as well as larger cogenerators, offshore wind plants and some generators in rural areas, such as village-scale biomass power plants. The wider network has some sections operating as synchronized AC.

But it also includes many AC-DC-AC links, using power electronics to transfer electrical energy while blocking AC disturbances. The wider network is also heavily instrumented, and carries continuous real-time two-way information, not only about flows of electricity but also about flows of value through the network. The instrumentation keeps the network stable, controlling not only generators but also suitably flexible loads, also instrumented with embedded microprocessors and other controls. Instead of always increasing generation to follow load, the instrumentation may also reduce or disconnect flexible loads to follow generation, as appropriate. It also keeps track of network services, who is providing them and who is using them - who pays and is paid, and how much.

Remote rural areas are not, however, connected to this network. They rely on self-contained local systems, that may include biomass power, wind power, photovoltaics and possibly batteries for storage, as well as appropriate system monitoring and control, also local.

In this high-reliability low-impact system, all the technologies described already exist. Such a system is already technically feasible. The network is still there, to provide back-up and arbitrage, and help ensure competitive pricing, on either a commodity basis or an asset basis.

However, by minimizing reliance on remote generation by large-scale hydro, coal-fired and nuclear power, and long-distance transmission, this configuration reduces both vulnerability to disruption and the traditional environmental impact of electricity. Indeed it is not an 'electricity system' but a 'services system', with contracts and prices to match. As a thought experiment, such a system therefore appears attractive. But it is still a thought experiment, a long way from reality. The reason is not technical, nor is it primarily one of cost, although cost is certainly a factor. The reason is fundamentally structural. The difference between the structure of existing electricity systems and that of a possible high-reliability low-impact system is profound.

> The technical, institutional and financial configurations of existing electricity systems reinforce each other. Any possible alternative configuration starts at a deep disadvantage. Even the anticipated costs of alternatives are assessed according to criteria used for existing systems, which may be completely inappropriate in the alternative context. For example, comparing the cost of electricity from a remote coal-fired power station with the cost of electricity from a photovoltaic roof on the building where it is to be used, without mentioning location, time of day and year, accounting basis or other system costs and risks, including the risk of disruption, is a grossly distorted comparison. But such comparisons have long been used to dismiss innovative generating technologies, by assuming they must fit into existing systems in the existing context. In any case, you must also ask 'The cost to whom? On what financial basis? Who carries the risks? Who pays for the environmental impacts?' Until such distortions are rectified, innovative technologies and configurations will always be undervalued and underestimated by traditional assessment procedures.[24]

Getting to this "alternative configuration" will be a challenge. As an initial step, Canadian environmental organizations have turned these broad principles into detailed scenarios and policy recommendations for Ontario in three recent complementary reports: *Phasing Out Nuclear Power In Canada* from the Campaign for Nuclear Phase-out[25]; *Power for the Future: Towards a Sustainable Electricity System for Ontario* from the Pembina Institute for Appropriate Development and the Canadian Environmental Law Association[26], and *Smart Generation: Powering Ontario With Renewable Energy* from the David Suzuki Foundation.[27] In addition, the Toronto Environmental Alliance has developed, in collaboration with the Low-Income Energy Network, a framework for ensuring that low-income households aren't left out of the green future.[28]

Power for the Future is the report which most directly addresses the issues of concern to the OPA (setting targets and undertaking a technical and economic analysis of the feasibility of the overall approach), so that is the report which will be focused on here, but it is interesting to note that *Phasing out Nuclear Power* comes up with similar figures for technical feasibility (using a very different approach from the CIMS model used in *Power for the Future*) while Suzuki Foundation explicitly builds on the analysis in *Power for the Future* in an effort to flesh out the analysis of the capacity and economic viability of renewable sources of energy.

The results of the *Power for the Future* report can be summarized as follows:

From the Executive Summary of *Power for the Future:*

In the fall of 2003, the Pembina Institute and the Canadian Environmental Law Association initiated an independent investigation of the technical and economic potential for energy-efficiency measures, fuel switching, distributed generation, load shifting (demand response), and low-impact renewable energy sources, such as wind, small-scale hydro and biomass, to provide the foundation for a more sustainable, reliable and affordable electricity system for Ontario.

Using the CIMS computer model developed by researchers as Simon Fraser University, the study found that electricity demand could be reduced by 40% against business-as-usual projections by 2020 through the adoption of currently available energy efficient technologies and practices, fuel switching and increased industrial and commercial cogeneration. Taking into account the potential contributions from demand response measures and on-site generation, the study found that projected summer peak grid electricity demand could be reduced by nearly 50%.

The cost of achieving these savings would be substantial. The investments in energy efficient technologies, fuel switching and increased cogeneration would be more than $18 billion over 15 years. But more than 95% of this amount would be recovered by energy consumers through energy cost savings.

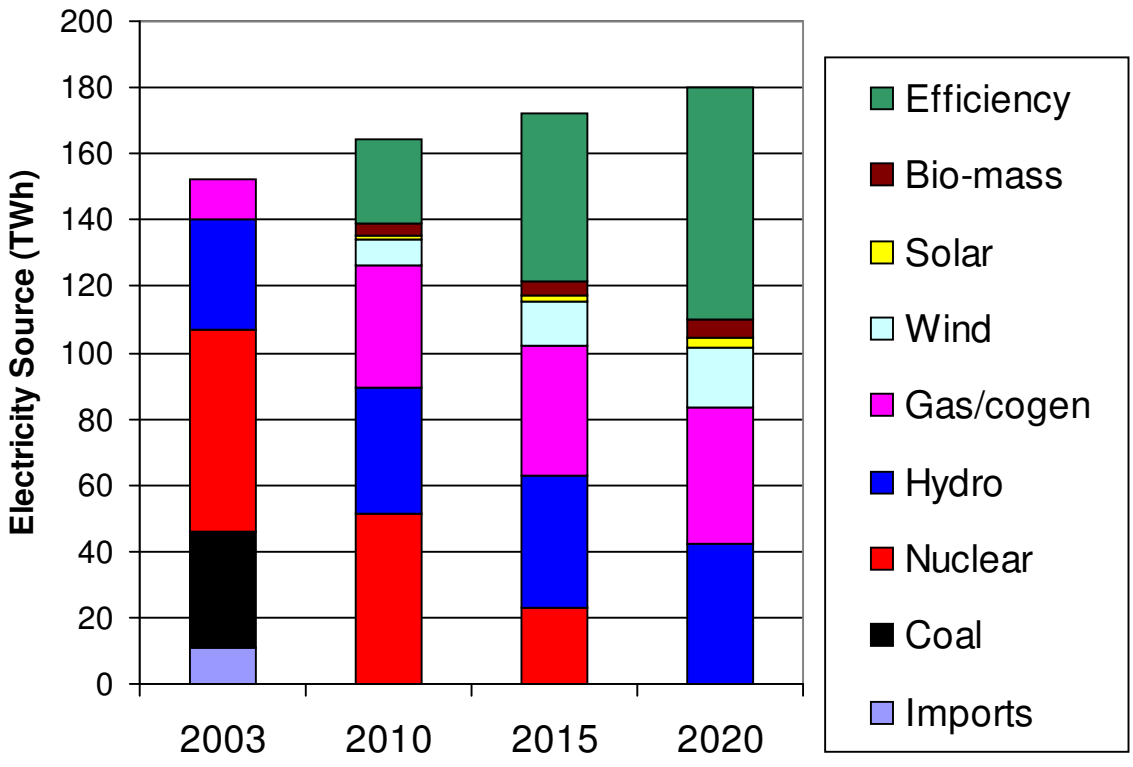
By contrast, providing the same amount of electricity that could be saved by these investments through the construction of new nuclear generating facilities would cost more than $32 billion.

The study also found that currently available renewable energy technologies could make major contributions to the province's future electricity supply. The study concludes that on the basis of environmental impact, safety and security, reliability, costs and construction time, the remaining grid demand, once the opportunities for energy efficiency and low-impact renewable energy sources have been maximized, should be met through new high-efficiency combined cycle natural gas fired generating facilities. The study found that by 2020 this requirement would amount to substantially less than the province's current coal-fired generating capacity.

Ontario faces major choices over its future electricity path and all of these choices entail a measure of risk. In contrast to the option of investing in the construction of new nuclear generating facilities, a technology that is in large measure responsible for the environmental, reliability and financial crises now facing Ontario's electricity system, the path outlined in the study relies on existing proven energy efficiency and low-impact renewable energy technologies. These technologies have well-established performance and costs, and major environmental, health, security, safety and reliability benefits relative to conventional sources of electricity supply. These factors make the best choice for Ontario's electricity future clear.

The shift from the current system mix, to one based on efficiency gains (or 'nega-watts'), renewable energy and additional natural gas is shown below graphically in Figure 5.

Figure 5: Proposed system mix in *Power for the Future* (Source: Winfield et al., 2004)



This scenario accepts the forecast of a 1.1% annual growth rate in energy consumption, but focuses on how to drive efficiency gains that reduce overall consumption. Coal-fired generation is eliminated by 2010, nuclear is phased out as existing plants come to the end of their lifespans, and renewables (low-impact hydro, wind, solar, and bio-mass) are added, with 4,400 MW of natural gas generation serving as a transitional technology. Efficiency gains contribute almost twice as much as new natural gas, while the proposed addition of 4,400 MW of natural gas capacity by 2020 is less that what the government is currently proposing as part of the coal phase-out plan. The system mix shown above also does not envisage any net imports after 2010, although if the proposed east-west grid were built it would probably result in a larger share for imported hydro power (which could have potentially negative environmental or social impacts in Manitoba or Quebec) and a lower share for natural gas.

It is also important to note that this proposed system mix is viable and cost-effective using today's technology (with 95% of the $18 billion investment in efficiency recouped by consumers through lower bills). There will, however, undoubtedly be future technological improvements that will improve the efficiency of energy use and reduce the cost of renewable energy.

To achieve this scenario, the Pembina report makes a series of detailed policy recommendations:

Policy Recommendations from *Power for the Future:*

1. The Government of Ontario should adopt minimum energy efficiency standards under the Energy Efficiency Act equivalent to the energy efficiency levels required for Energy Star labelling for all major electricity-using devices and equipment when the market share for new or replacement energy efficient models surpasses 50%, and not later than 2010 for all devices. The province should develop its own energy efficiency standards for equipment not covered by Energy Star.

2. The provincial Building Code should be amended to require R2000, Canadian Building Improvement Program (CBIP), or equivalent energy efficiency performance for all new buildings and building renovations by 2010.

3. The Planning Act should be amended to permit municipalities to make energy efficiency design requirements a condition of planning and site approvals for new developments.

4. The most energy efficient technologies in all sectors and end-uses should be labelled through the Energy Star program or, if not included in Energy Star, through a provincial labelling system.

5. The OEB performance-based rate setting and DSM incentive mechanism model currently applied to Enbridge Gas Distribution should be extended to Hydro One and all of Ontario's electrical distribution utilities. All distribution utilities should be required to set targets for energy efficiency gains and be allowed to then share in the benefits of DSM programs. The incentive mechanisms should allow utilities without DSM capabilities to meet their targets by contracting the delivery of DSM programs to other electrical and gas utilities, the energy service industry, or specialized non-profit agencies.

6. The Government of Ontario should expand its current net metering policy to include all industrial, commercial/institutional and residential users, and develop grid inter-tie specifications and training programs for utility staff. A series of annual special RFPs or feed-in tariffs should be issued to encourage smaller industries and large commercial and institutional facilities to develop their cogeneration potential.

7. The Government of Ontario should establish a partnership with utilities, financial institutions, energy service companies, municipalities, and other stakeholders to offer a series of financing mechanisms to assist electricity consumers in all sectors to finance the adoption of energy efficient products and technologies and measures out of the savings they will achieve through these investments.

8. The Government of Ontario should enter into an agreement with the federal government under the auspices of the federal government's Kyoto Protocol implementation plan to share the costs of providing the following financial incentives for the adoption of energy efficient technologies:

- Grants for high efficiency home energy retrofits and new R2000 homes;
- Grants towards the additional cost of new high-efficiency commercial buildings and commercial building retrofits;
- Sales tax rebates for all Energy Star products in all sectors and small-scale renewable energy power sources;
- Business tax credits for industrial energy efficiency equipment and cogeneration systems;
- These incentives should focus initially on technologies where the largest reductions can be achieved at the lowest cost, such as commercial HVAC and lighting and industrial drive power. The incentives should be in effect only until the market share of the efficient technology reaches 50%.

9. Mechanisms to ensure the delivery of programs to low-income consumers should be incorporated into the DSM mandates and incentives provided to energy and electrical distribution utilities. A specific portion of DSM spending should be set aside for this purpose, including revenues from the Public Benefits Charge proposed in Recommendation 11.

10. The Government of Ontario should adopt legislation creating a new agency, the Ontario Sustainable Energy Authority, reporting to the Minister of Energy, to lead and coordinate the province's energy efficiency efforts. The agency's functions should include:

- The coordination and oversight of the development and implementation of provincial energy efficiency standards and labelling programs;
- Ensuring the consideration of energy efficiency in the policies and programs of provincial government agencies;
- The ongoing assessment of the effectiveness of energy efficiency programs being delivered by utilities and provincial agencies, including low-income programs and the provision of recommendations for their improvement to the provincial government and the OEB;
- The forecasting of province's future electricity needs;
- Research, development, and education and information dissemination on energy efficient technologies and practices. The proposed Ontario Power Authority, responsible for issuing requests for proposals for the construction of new generating capacity, should be a division of the new agency.

11. A Public Benefit Charge (PBC) of 0.3 cents/kWh should be applied on all electricity sales to finance energy efficiency and low-income assistance programs.

12. The Government of Ontario should implement the following demand response policies:

- The OEB should be directed to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market.
- The Government of Ontario should assess the infrastructure needed to encourage and facilitate demand response in the Ontario market. A portion of the revenues generated by the PBC proposed in Recommendation 11 should be used to meet the costs of providing the required infrastructure.
- All electricity consumers should be able to participate in demand response programs, and should not be capped in terms of the level of their participation.

13. The Government of Ontario should undertake a design and costing study for a 200,000 unit solar PV roof program modelled on those undertaken in Europe and the United States, and implement this program using a feed-in tariff funding mechanism.

14. The Government of Ontario should issue, through the IMO or proposed Ontario Electricity Authority, RFPs for supply from wind, upgraded existing or new small scale hydro, solar, the use of waste-generated methane from municipal, agricultural, industrial sources and other low-impact renewable energy sources. The initial RFPs should seek to have 4,500 MW capacity in place by 2010, followed by additional calls for supply up to 7,100 MW by 2015 and 9,800 MW by 2020.

15. The Government of Ontario should undertake on an urgent basis a complete up-to-date assessment of the potential contributions from onshore and offshore wind generation, small scale

hydro and the use of waste digestion-generated methane to the province's future energy supply. This effort should include primary research as required, including detailed wind-potential mapping.

16. The Government of Ontario should initiate a research and development program on renewable energy technologies funded through the PBC proposed in Recommendation 11. This should include both technology development and the resolution of grid integration issues.

17. The IMO should adopt management practices designed to forecast power outputs from wind power capacity and run-of-river hydro (and solar PV systems), and be prepared to dispatch hydro storage and existing natural gas facilities as needed to provide base load capacity.

18 The Government of Ontario should establish and expedite the completion of a consultative process to develop land-use guidelines for the siting of renewable energy generating facilities.

19. The Government of Ontario should develop guidelines, in conjunction with the federal government, for the approval of offshore wind power generation facilities.

20. The Government of Ontario should issue through the IMO or the proposed Ontario Electricity Authority a request for proposals for long-term base load supply, meeting the construction time, cost, reliability, and environmental, health and safety performance of combined cycle natural gas generating facilities. The call for proposals should seek to have 4,200 MW of new base load supply in place by 2007 and 4,500 MW in place by 2020.

Building on the detailed work on efficiency in the Pembina/CELA report, the David Suzuki Foundation study, *Smart Generation: Powering Ontario with Renewable Energy*, expanded on the renewables analysis to demonstrate that it is possible to install more than 12,000 megawatts of renewable energy capacity producing over 35 terawatt hours annually by 2020. This would create 25,000 jobs in the renewable energy sector by 2010 and 77,000 jobs by 2020 and produce nearly $14 billion in economic benefits by installing 8,000 megawatts of wind energy alone. There would also be benefits beyond the kilowatts generated, as renewable energy (e.g. solar thermal or geothermal) is used to replace natural gas and electricity currently used for heating and cooling homes, offices and industries in Ontario.

Conclusion

We have the intellectual, technical and economic capacity to design and build a leaner, greener electricity system based upon the efficient use of decentralized, low-impact renewable energy to meet genuine energy needs.

The investments and regulatory changes required to achieve this 'green' future, however, cannot and will not be made if the province opts to go down the path of new and/or refurbished nuclear power stations. The nuclear option would absorb so much of the financial, political and intellectual capital within the electricity system that there wouldn't be the capacity for more than a token gesture towards the efficiency / green power option.

The analyses and recommendations put forward by the Pembina Institute and the David Suzuki Foundation will move us in the direction of a more sustainable electricity system. But at root, it will require a different approach to electricity – one based on meeting needs rather than producing kilowatts.

This is where the Ontario Power Authority can truly make a difference. The OPA is the body that has been given the task of thinking about the future of the system as a whole, and will

have to choose between entrenching the status quo or proposing a bold new vision of a greener, decentralized energy system.

This will require vision and a certain amount of political courage on the part of the OPA and the provincial government, for there are no powerful interests within the current policy community set to defend the needs of a green energy industry that doesn't yet exist, or of future generations that will live with the environmental legacy we leave behind.

There is, however, broad public support for such a vision and many organizations within civil society committed to working with policy-makers to bring this vision to reality. Tapping into this support, and mobilizing even a portion of the political, financial and intellectual effort that went into creating a domestic nuclear industry, to help make this green alternative a reality, is the task that awaits us over the next twenty years.

Endnotes

[1] Keith Stewart is the Smog and Climate Change Campaigner for the Toronto Environmental Alliance, a non-profit environmental organization.. He wrote his Ph.D. on environmental policy in Ontario at York University and is the co-author of *Hydro: The Decline and Fall of Ontario's Electric Empire* (Toronto: Between the Lines, 2004). Please send any comments on this analysis to keith@torontoenvironment.org .

[2] Dwight Duncan, "Choosing What Works For a Change", Speech by the Ontario Minister Of Energy to the Empire Club (Toronto: April 15, 2004).

[3] Watson, R.T. and the Core Writing Team (Eds.) *Climate Change 2001: Synthesis Report: A contribution of Working Groups I, II and III to the Third Assessment Report of the Intergovernmental Panel on Climate Change* (Cambridge University Press: 2001).

[4] "A significant and unique feature of this issue [nuclear waste] is the time dimension. When used fuel is removed from a nuclear reactor it is highly radioactive and requires proper shielding and careful handling to protect humans and the environment. Although the radioactivity decreases with time, used fuel remains a potential health, safety and security hazard for a very long period, likely tens of thousands of years or longer. We are contemplating designing and licensing a system for periods longer than recorded history." Source: Nuclear Waste Management Organization, *Choosing a Way Forward: The Future Management of Canada's Nuclear Fuel: Executive Summary of Draft Study Report* (Nuclear Waste Management Organization: 2005), p. 2.

[5] David Nye, *Consuming Power: A Social History of American Energies* (Cambridge: MIT Press, 1998), quotes are from page 253.

[6] Walt Patterson, "Overview: The Electric Challenge" Keeping the Lights On: Working Paper No. 1 (Royal Institute of International Affairs: March 2003). See also Walt Patterson, *Transforming Electricity,* (RIIA/Earthscan: 1999). For an interesting analysis of electricity 'markets' given the particular nature of this non-comodity, see Mark Cooper, *Electricity Deregulation and Consumers: Lessons from a Hot Spring and a Cool Summer*, (Consumer Federation of America, August 30, 2001).

[7] Walt Patterson, "Overview: The Electric Challenge" Keeping the Lights On: Working Paper No. 1 (Royal Institute of International Affairs: March 2003), pp. 8-9.

[8] For a partial history of this campaign, see Jamie Swift and Keith Stewart, *Hydro: The Decline and Fall of Ontario's Electric Empire*, (Toronto: Between the Lines, 2004).

[9] Ontario's coal plants emitted 35,252 kilotonnes of carbon dioxide in 2002 according to Ontario Power Generation's *Towards Sustainable Development: 2002 Progress Report*. Ontario as a whole emitted 203,000 kilotonnes of carbon dioxide equivalent in 2002 according to Environment Canada's *Greenhouse Gas Inventory 1990 – 2002*, (August 2004).

[10] Ministry of the Environment, *Coal-fired Electricity Generation in Ontario*, (2001).

[11] This limited range of options was evident in the report the Ontario Ministry of Energy commissioned on the costs and benefits of replacing Ontario's existing coal plants, in which the only options examined were imposing stringent emissions control technologies on existing coal plants, refurbished and/or building new nuclear reactors, and building natural gas-fired generating stations. See DSS Management Consultants Inc. and RWDO Air Inc., *Cost-Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation*, report prepared for the Ontario Ministry of Energy (April 2005).

[12] Hon. Jake Epp, Peter Barnes and Robin Jeffrey, *Report of the Pickering "A" Review Panel*, Report to the Ontario Minister of Energy, (December 2003).

[13] Bryn Sadownik, John Nyboer, Rose Murphy and Alison Laurin, "Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario", final report to the Pembina Institute for Appropriate Development from M.K. Jaccard and Associates Inc., (New Westminster, BC: April 27, 2004).

[14] Electricity Conservation and Supply Task Force, Tough Choices: Addressing Ontario's Power Needs, Final Report to the Minister (January 2004), pp. 18-19.

[15] Quote is taken from the Ontario Power Authority's "Call for Written Submissions" on the Supply Mix.

[16] For a more detailed treatment, see Jamie Swift and Keith Stewart, *Hydro: The Decline and Fall of Ontario's Electric Empire*, (Toronto: Between the Lines, 2004).

[17] Paul McKay, *Electric Empire: The Inside Story of Ontario Hydro*, (Toronto: Between the Lines, 1983), p. 176.

[18] Paul McKay, *Electric Empire: The Inside Story of Ontario Hydro*, (Toronto: Between the Lines, 1983), chapter 7.

[19] Quoted in Jamie Swift and Keith Stewart, *Hydro: The Decline and Fall of Ontario's Electric Empire* (Toronto: Between the Lines, 2004), p. 173.

[20] The following tables are taken from Ralph Torrie, "Greening Ontario's Electricity Sector: From Crisis to Opportunity", Presentation to the Greening Ontario's Electricity Future conference in Toronto, January 30, 2004.

[21] Ibid.

[22] These principles were developed in the literature on the 'soft energy path', the foremost Canadian example being The Science Council of Canada, *Canada as a Conserver Society: Resource Uncertaintes and the Need for New Technologies*, report number 27, (Ottawa, September 1977). See also David Brooks, *Zero Energy Growth for Canada*, (Toronto: McClelland and Stewart, 1981) and Amory Lovins, "Energy Strategy: The Road not Taken?", *Foreign Affairs*, (October 1976).

[23] On this latter point, see the reports of the Ontario Low-Income Energy Network at www.lowincome.ca .

[24] Walt Patterson, "Networking Change" Keeping the Lights On: Working Paper No. 3, (Royal Institute of International Affairs, June 2004), pp. 13 – 15.

[25] Ralph D. Torrie and Richard Parfett, "Phasing Out Nuclear Power In Canada: Toward Sustainable Electricity Futures", report prepared for the Campaign for Nuclear Phaseout by Torrie Smith Associates, (July 2003).

[26] Mark S. Winfield, Matt Horne, Theresa McClenaghan and Roger Peters, *Power for the Future: Towards a Sustainable Electricity System for Ontario* (Toronto: The Pembina Institute for Appropriate Development and the Canadian Environmental Law Association, 2004).

[27] Jose Etcheverry et al., *Smart Generation: Powering Ontario with Renewable Energy*, (Vancouver: David Suzuki Foundation, 2004).

[28] See *Low Income Energy Conservation and Assistance*, report prepared by Indeco Consulting for the Toronto Environmental Alliance (April 2004), available at www.lowincomeenergy.ca and www.torontoenvironment.ca.

TORONTO

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August 24, 2005

The Honourable Dwight Duncan
Minister of Energy
900 Bay Street, 4th Floor
Hearst Block
Toronto, Ontario M7A 2E1

Subject: Recommendations on Ontario's Future Energy Supply Mix

Dear Minister Duncan:

I am pleased to provide recommendations on the future energy supply mix for Ontario. These comments are offered in response to the Ontario Power Authority's call for written submissions, and in light of the transformations taking place in Ontario's energy sector.

Toronto Public Health's most recent assessment indicates that poor air quality contributes to approximately 1,700 premature deaths and 6,000 hospitalizations each year in Toronto. I am encouraged by the Government of Ontario's efforts to reduce this health burden by phasing out coal-fired electricity generation in the province. However, the next steps are critical in determining whether Ontario's energy future will help protect health or continue to create health risks.

Future Energy Supply Mix:

Developing Ontario's energy strategy is an opportunity to make healthy, sustainable choices that will benefit Ontarians over the long term. From a health risk-reduction perspective, I urge the Government of Ontario to give clear priority to reducing demand through energy conservation and providing energy from low-impact, renewable sources, rather than nuclear energy. This approach, combined with cleaner-burning natural gas as an interim measure, can be used to balance energy supply and demand in Ontario. A truly innovative energy conservation strategy can reduce our reliance on fossil fuels and improve environmental quality, reducing overall health risks.

Energy Conservation:

To date, the Government of Ontario has committed to reducing Ontario's peak energy demand by five percent by 2007. According to a 2004 study by the Pembina Institute and the Canadian Environmental Law Association, Ontario is capable of reducing energy demand by 40 percent by the year 2020, relative

to the business as usual case. This would be achieved by a combination of financial incentives, financing approaches, and reduced impediments to cogeneration. Reducing energy demand lowers fossil fuel consumption and helps to clean our air. I recommend that the Government of Ontario commit to achieving ambitious reductions in energy demand by 2020, by pursuing these innovative approaches to conservation. Also, I urge the Government of Ontario to empower Ontario's Chief Energy Conservation Officer to immediately develop and implement a far-reaching conservation plan for Ontario to achieve this goal.

Renewable Energy:

The Government of Ontario has committed to a renewable portfolio standard ensuring that five percent (1,350 MW) of Ontario's energy comes from new renewable sources by 2007, and ten percent (2,700 MW) by 2010. According to the Pembina Institute and the Canadian Environmental Law Association (2004), Ontario is capable of producing more than 55 percent of its energy supply from renewable sources by 2020, if implemented in concert with the aggressive energy conservation measures outlined above. Renewable energy sources, in combination with net metering and other complementary approaches, offer long-term air quality and health benefits over conventional sources of energy. I challenge the Government of Ontario to follow-up its commitment to phase out coal by achieving aggressive targets for low-impact, renewable sources of energy by 2020.

To help lower the short- and long-term health risks associated with the energy we use, I urge the Government of Ontario to emphasize energy conservation and renewable energy sources in its approach to Ontario's energy supply, as described above.

Sincerely,

ORIGINAL SIGNED BY

David McKeown, MDCM, MHSc, FRCPC
Medical Officer of Health

cc: Donna Cansfield, Parliamentary Assistant to the Minister of Energy
Mr. Jan Carr, Chief Executive Officer, Ontario Power Authority
Peter Love, Chief Energy Conservation Officer, Ontario Power Authority
Councillor John Filion, Chair, Board of Health, City of Toronto

July 29, 2005

Via Email and Mail

Ontario Power Authority
Attn: Generation Procurement
175 Bloor St. East
North Tower, Suite 606
Toronto, Ontario
M4W 3R8

Re: Ontario Power Authority (OPA) Procurement Process for Electricity Resources

Total Energy Advice & Management Ltd. (TEAM) is pleased to provide input into the OPA's process to determine the most appropriate manner in which to develop electricity resources in Ontario. TEAM has provided this written submission in order to provide a high level outline of TEAM's positions and opinions on various relevant issues.

Please feel free to contact me if you have any questions or would like to discuss TEAM's responses further. I can be reached at (416) 223-4699 or via email at Lawrence.Wu@TheTeamLtd.com.

Sincerely,

Lawrence Wu, P. Eng.
Partner
Total Energy Advice & Management Ltd
(TEAM)

Response to OPA Stakeholder Questionnaire

Conservation and Demand Management (CDM)

About TEAM

Total Energy Advice & Management Ltd. (TEAM) is a privately held corporation under the laws of Ontario. There are 5 shareholders/partners in TEAM – Bruce Fraser, CMA, Lucie Gervais, Murray Ross, Linda Wainewright and Lawrence Wu, P. Eng. With well over 100 years of energy experience in total, the 5 partners in TEAM provide senior level commitment and expertise from start to finish to each of our clients.

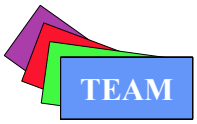
TEAM, through the activities and experience of its partners, has been involved in various projects that support CDM activities. During the past two years, TEAM's partners have been involved in the following CDM and power generation activities.

- IESO Transitional Demand Response Program – Verification & Audit methodology and implementation
- A large co-generation project – Financial modeling and cash flow analysis including combined heat and power requirement and electricity sales to the IESO market and the financial settlement calculation of the Ontario Government's 2500 MW RFP.
- Energy Management System– Design and implementation of a multiple location (40 schools) computerized real time energy management system for a large district school board, including assisting in the selection of various vendors
- Demand Response and Demand Side Management Program – Prepared a business plan of a demand response and demand side management project.

TEAM provides a total energy management approach to our clients. TEAM assists our clients in meeting their electricity needs by using a portfolio approach in sourcing electricity, implementing or participating in CDM programs and tracking their performance so that adjustments in the portfolio can be made from time to time. TEAM believes that the weighting of the CDM measures in our clients' portfolios will increase as the Ontario Government, the OPA, the IESO, the LDCs, energy retailers and others implement more CDM initiatives.

CDM Barriers/Opportunities

There are currently three main barriers to implementing CDM in Ontario: the complexity of the process, the lack of attractive market incentives to encourage commercial participation and effective marketing to reach end users regarding the CDM activities.



The realistic opportunities for CDM in Ontario will be in the area of demand response in order to reduce the generation and transmission capacity requirements in Ontario. If the true avoided cost of the generation, transmission, distribution and other environmental benefits are passed to the end users who participate in demand response programs, there would be a significant increase in demand response. The Ontario Government's smart metering initiatives can be used to support demand response programs.

In other CDM areas, the OPA would encourage the creativity of the market to find CDM solutions that work by providing an incentive, but not limiting the number of categories of CDM opportunities.

CDM Payments

The payment for CDM should be made by those who benefit from the CDM activities. The benefits of CDM should include the avoided cost of generation, transmission, distribution and other environmental and social benefits such as job creation etc. The electricity system related benefits should be paid by the electricity consumers while the environmental and social benefits should be paid by taxpayers.

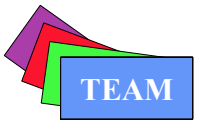
TEAM supports equality of CDM measures and does not believe there needs to be a differentiation between in front of and behind the meter initiatives as long as the incentive payments are equally accessible to all who implement CDM measures in a transparent manner.

Reductions in line losses reduce energy consumption especially during supply shortage times. Therefore, they should be included in the evaluation.

CDM Structural Issues

CDM Programs can be successful at any level. TEAM supports an environment in Ontario where all vendors of CDM initiatives have equal opportunity to succeed in a market where the rules around incentives are known and clear and there is a transparency to the process. TEAM believes in the benefits of competition – especially when ratepayer or taxpayer dollars are on the table.

Different types of organizations (centralized, LDC/regional groups, NGOs, electricity retailers, OPS etc.) bring their own strengths to their clients. TEAM does not support limiting who can or will participate in providing CDM programs. Rather TEAM supports having a transparent market with known rules, boundaries, and guidelines. Two given end-users may each have relationships with their electricity LDC, an electricity retailer, and a particular NGO. Yet each end-user may choose a different supplier for their CDM program than the other. TEAM believes that choice through competition will support the most cost effective model of delivering CDM programs.



CES Process

TEAM partners participated in the CES process. TEAM was aware of potential bidders who decided not to bid because the opportunity cost of the time required to put together a bid was far too high.

Overall, TEAM felt the CES process was reasonably fair for large projects and too onerous for projects at the minimum of 5 MW. TEAM believes that using a simpler process, a number of additional smaller projects would have been proposed and possibly accepted.

The existing process is open and well informed. The only suggestion TEAM has is to increase the timeline so that market participants will have sufficient time to prepare for the bid.

Non-electricity products and intangible benefits

TEAM supports the concept of monetizing these types of benefits whenever possible.

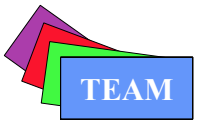
Alternate Processes

The scenario where the OPA sets pricing criteria, and proponents bid what project specifications can be offered at the set pricing criteria is similar to the standing offer, except the OPA not only sets the price, but also selects the proposals that go ahead. While TEAM sees that there are benefits to the existing process for generation projects, TEAM believes that the standing offer procurement option offers a more transparent option and is, therefore, a better solution for Ontario - particularly for CDM projects.

TEAM supports the standing offer procurement method where the rules and guidelines are clearly understood by everyone in the market. TEAM suggests that the OPA ensure that whatever detailed process is used, there is underlying and ongoing support by the Ontario government for the procurement process. This will provide some confidence to those who are building new facilities that their projects should be completed prior to any rule changes.

The standing offer criteria should be at a high enough level to allow for creative CDM solutions that are able to prove their value. TEAM supports a process that encourages creativity and new technologies to the extent possible.

It is not clear to TEAM how sole source negotiations would fit into the transparent and competitive market that we support.



Overall Comments – Future Process

Overall, TEAM supports a process that is simple, transparent and encourages CDM projects that benefit Ontario and improve the electricity supply/demand situation. The process should be as simple as possible in order to allow the process to be an acceptable solution regardless of the market structure – hybrid between regulated and competitive or completely competitive.

Submission by Trebilcock and Hrab is copyrighted. Citation as follows.

Michael J. Trebilcock and Roy Hrab, "Electricity Restructuring in Canada," in F. Sioshansi and W. Pfaffenberger (eds.), International experience in restructured electricity markets: What works, what does not, and why? (Elsevier, forthcoming 2006).

Hello,

I would like to express my support for the energy future in Ontario to be comprised of a mix of energy supply options containing 60% renewables. I also feel that energy efficiency and conservation are of the utmost importance, as this will ensure the lowest possible energy demand will have to be met. By taking the necessary action through investment in renewable and the long-term future, Ontario will not only become a role model by demonstrating that a safe and secure energy supply can be obtained, but its citizens will reap environmental, economic and social benefits on a large scale.

Thank you,

Stefan Tylak

The Dawn Hub

Presented to OPA

August 15, 2005

Steve Baker

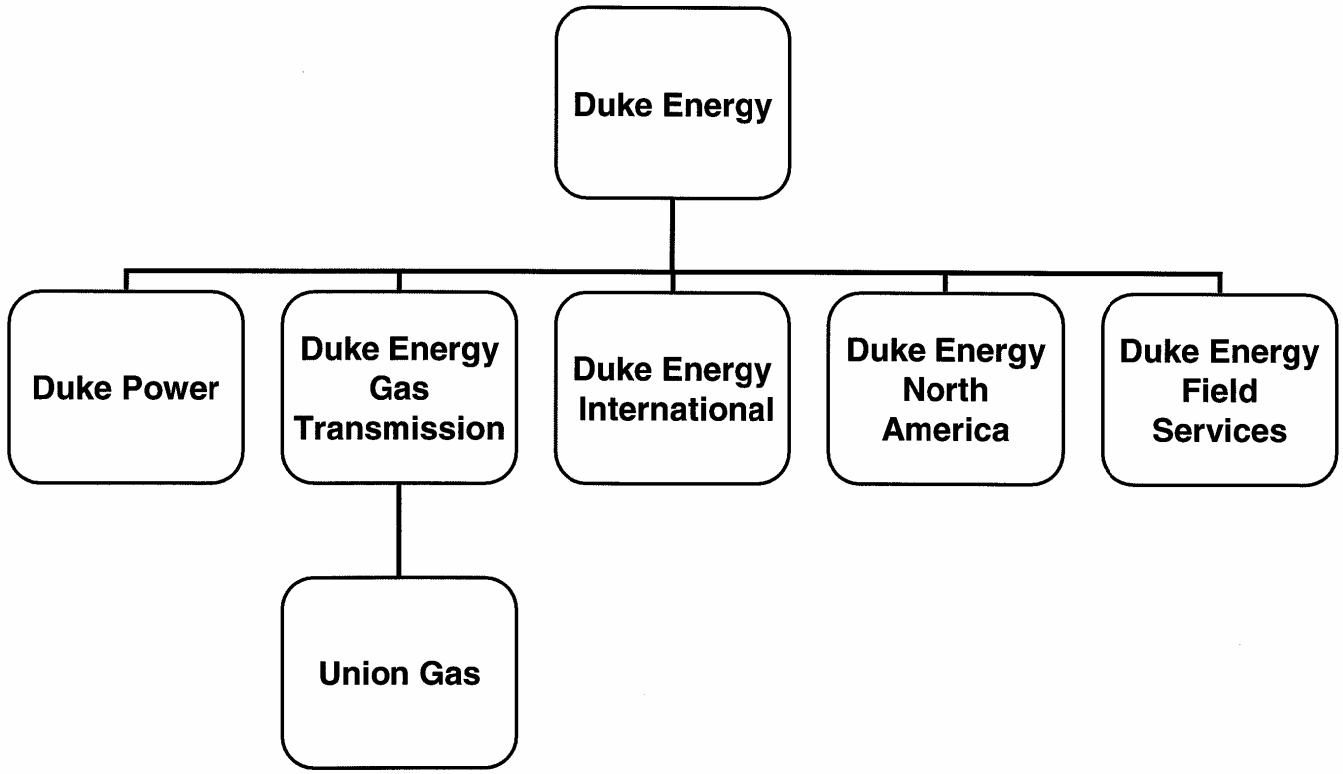
Vice President, Business Development & Commercial Accounts

Agenda

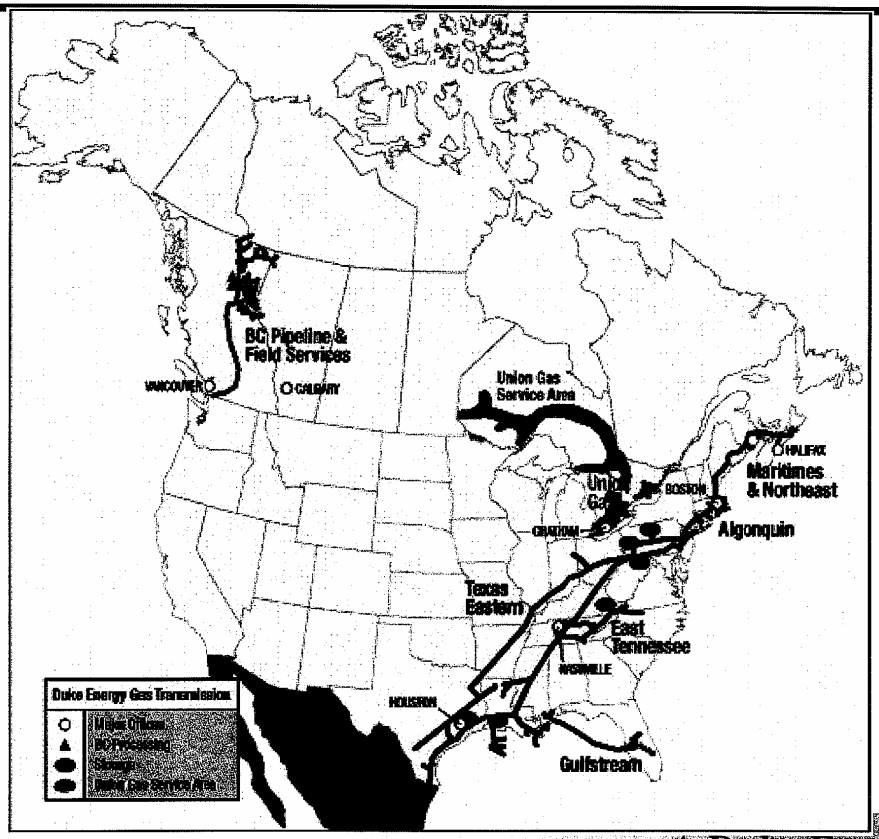
- Overview of Union Gas
- Overview of the Dawn Hub
- Drivers for Dawn Growth
- Union Gas Expansion
- Impacts of Ontario Power at Dawn
- Conclusion

Overview of Union Gas

Duke Energy Organization
Major Business Units



Duke Energy Gas Transmission System



Who is Union Gas?

- 2004 EBIT $356 million Cdn (8.6% of Duke)
- Assets (2004) -- $3.9 billion Cdn

A. Distribution:

- 1.2 million customers
- 24,000 miles of distribution pipelines
- Distribution volume (2004) -- 510 Bcf/year
- Union Gas provides system supply for 125 Bcf/d (approximately $1.1 billion/year

B. Transmission & Storage:

- Transport volume (2004) -- 776 Bcf
- 3,000 miles of transmission pipelines
- Working storage (2004) -- 155 Bcf

Upstream Assets

- Union Gas manages upstream assets for bundled direct purchase and sales customers
- Total Pipe assets (November 1, 2005)
  - ❑ TCPL — 456,261GJ/d – connects to WCSB
  - ❑ Alliance — 84,405 GJ/d – connects to WCSB
  - ❑ Vector — 168,810 GJ/d – connects to Chicago
  - ❑ Trunkline — 23,211 GJ/d – connects to U.S. Gulf
  - ❑ PEPL FZ — 26,376 GJ/d – connects to Mid-continent/Rockies
  - ❑ TBD — 36,927 GJ/d
- On an annual basis equivalent to 250 Bcf/year

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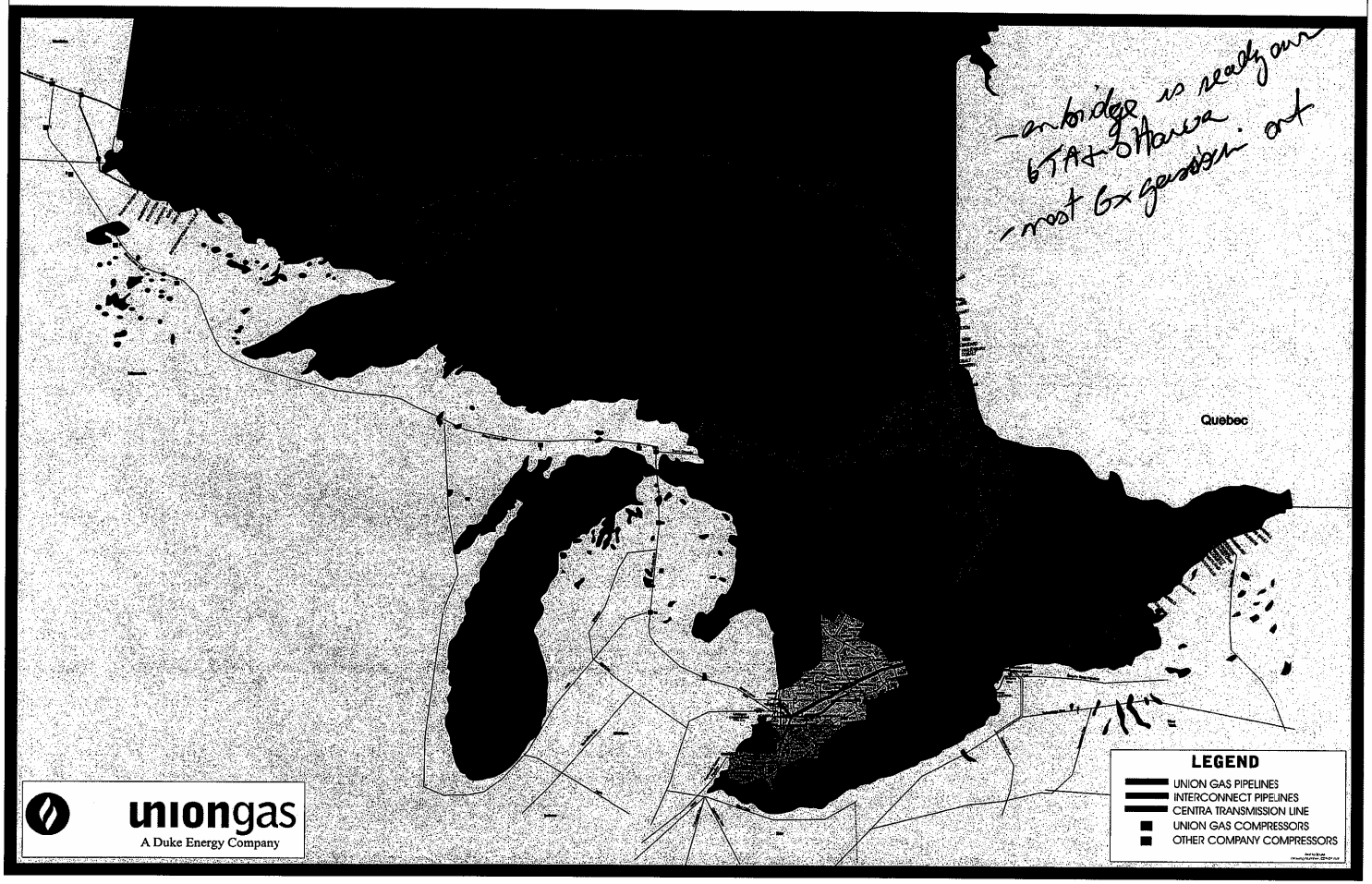
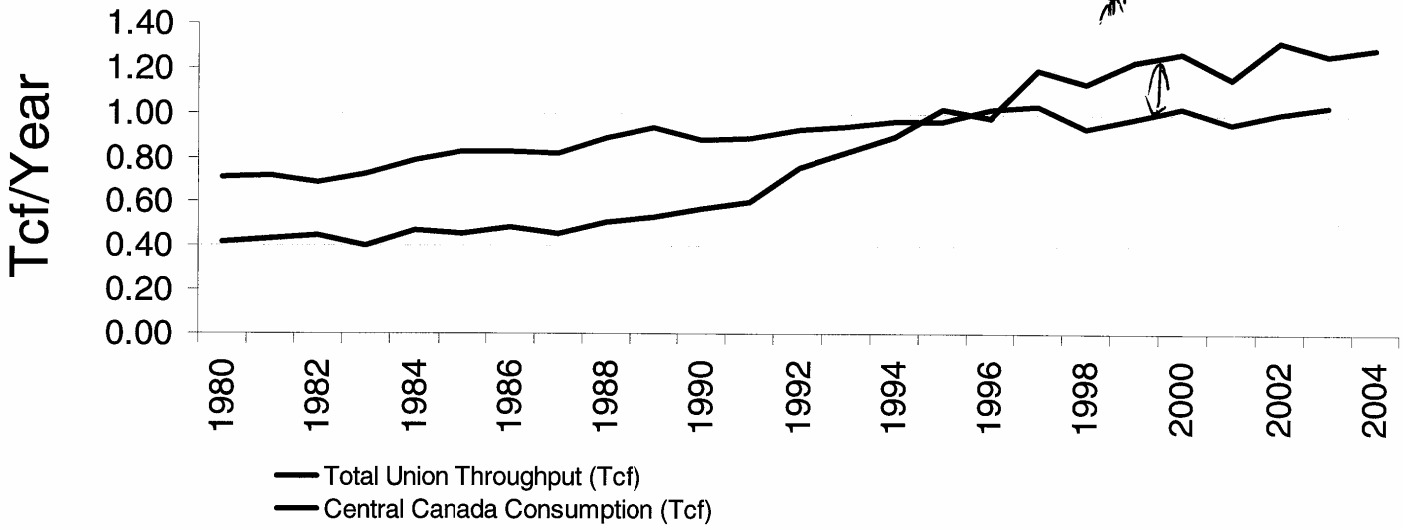
Union Gas Service Territory



Union throughput and Central Canadian Consumption (Tcf)



Union Gas Serves:
Gas-Fired Generation Service

Today, Union Gas already serves dispatchable gas-fired generation.

90% of gas-fired generation in Ontario is served directly by Union Gas.*

- 2200 MW of independent power
- 2140 MW at OPG Lennox

Southern Ontario

- Approximately 1300 MW of the independent power served with no notice T1 service integrating distribution and storage.

Northern & Eastern Ontario

- Approximately 900 MW of the independent power served with Rate 20/25/100 and CBS.

* Both Nanticoke and Atikokan use gas as a supporting fuel (ie. ignition)

Overview of Dawn HUB

BEA - Energy Env. Analysis

Characteristics of a Strong Hub

1. Physical Infrastructure at Hub

- ❑ Options for buyer/seller increase as number of interconnecting pipelines increase
- ❑ Existence of storage adds economic options

2. Size of Market

- ❑ Physical Throughput
- ❑ Total Transactions
- ❑ Index Liquidity

Characteristics of a Strong Hub

3. Price Transparency/Price Behaviour

- ❑ Accurate price information available from publications and on-line sources
- ❑ Price convergence for similar transactions

4. Number of Potential Buyers and Sellers

Strength of 1 – 4 = Liquidity

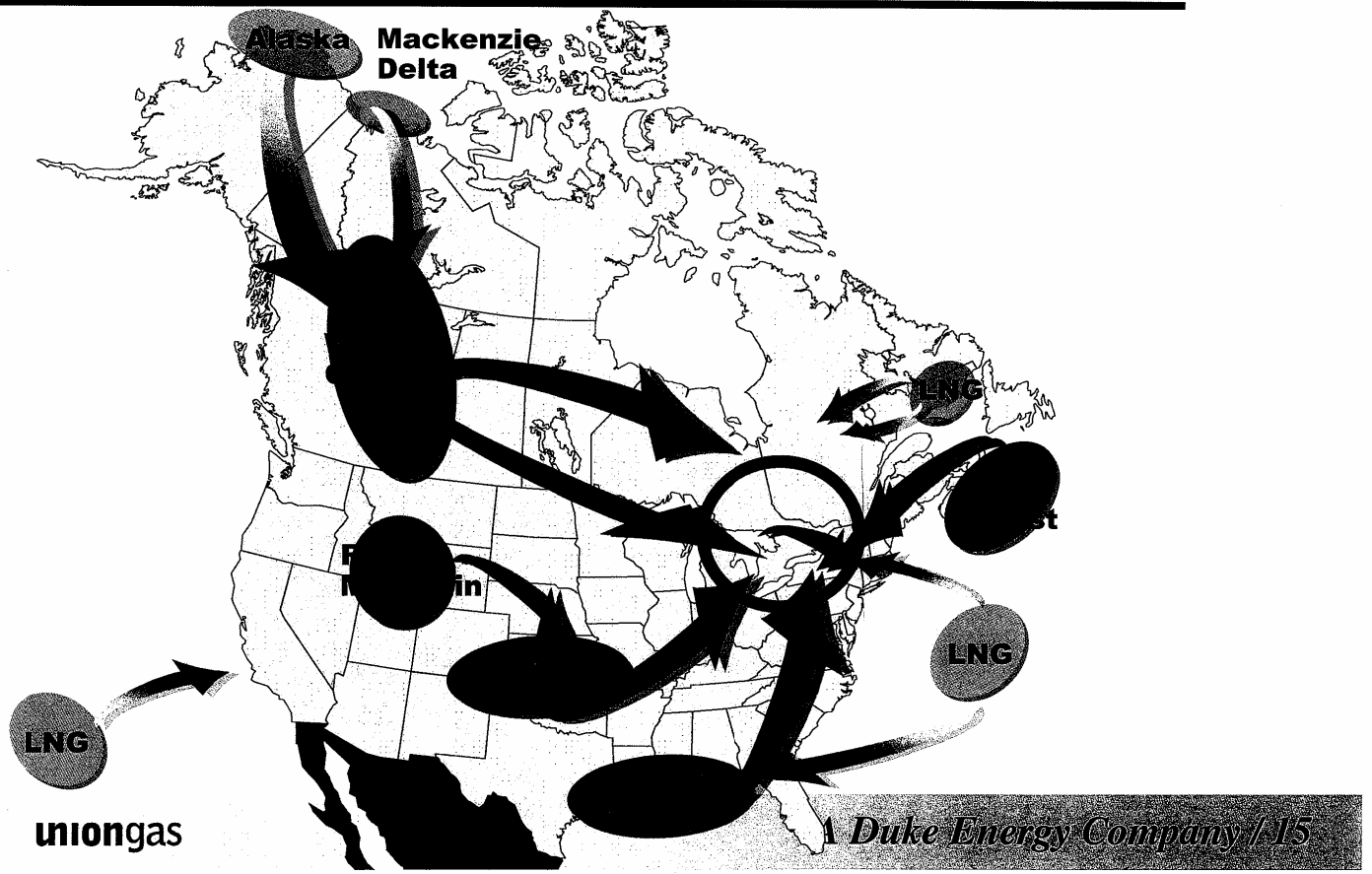
*Source EEA

Attributes that make Dawn a Strategic Market Hub

- Access to all major supply regions
- Physical infrastructure at the hub
  - ↗ **Including multiple pipeline interconnections & presence of storage**
- Size of market and volume of transactions
- Number of parties participating at the hub
- Price transparency and price behaviour
- Dawn is not controlled by one party. It is successful because of the combined assets and services of many different stakeholders.

Source – EEA – Review of Natural Gas Liquidity Concepts

Natural Gas that can Supply Ontario



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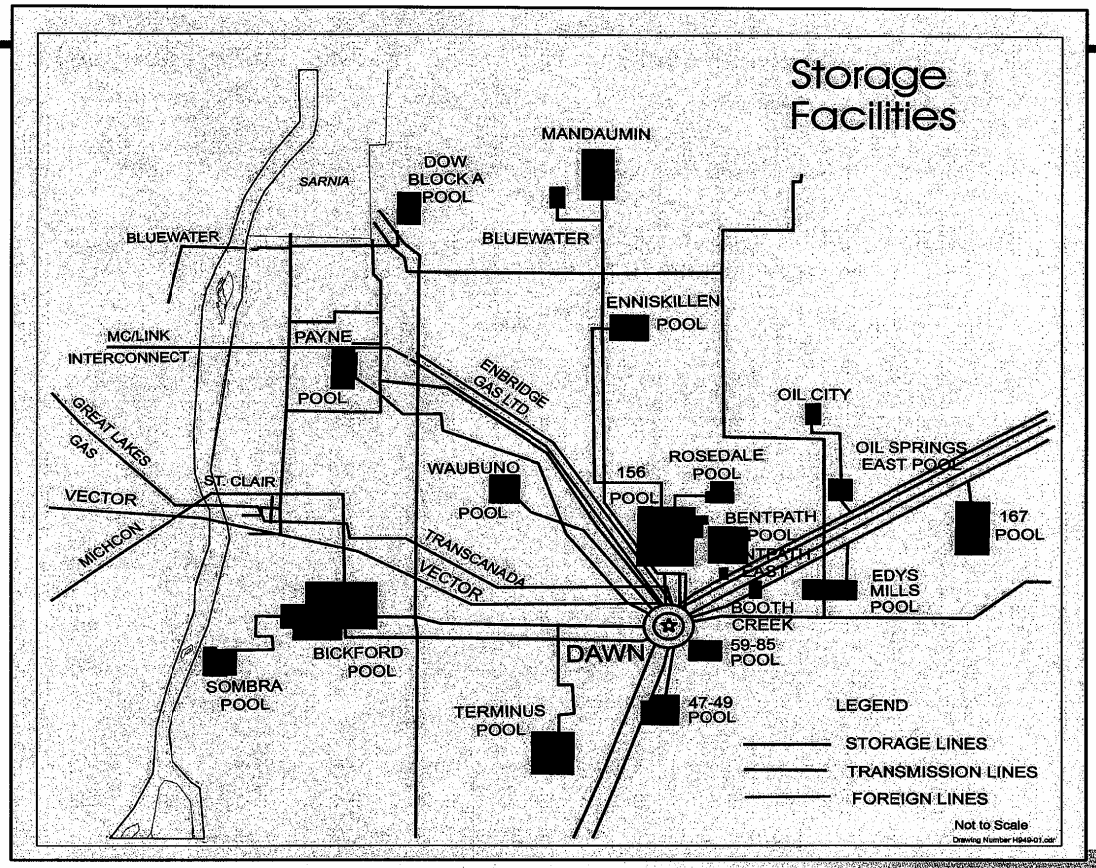
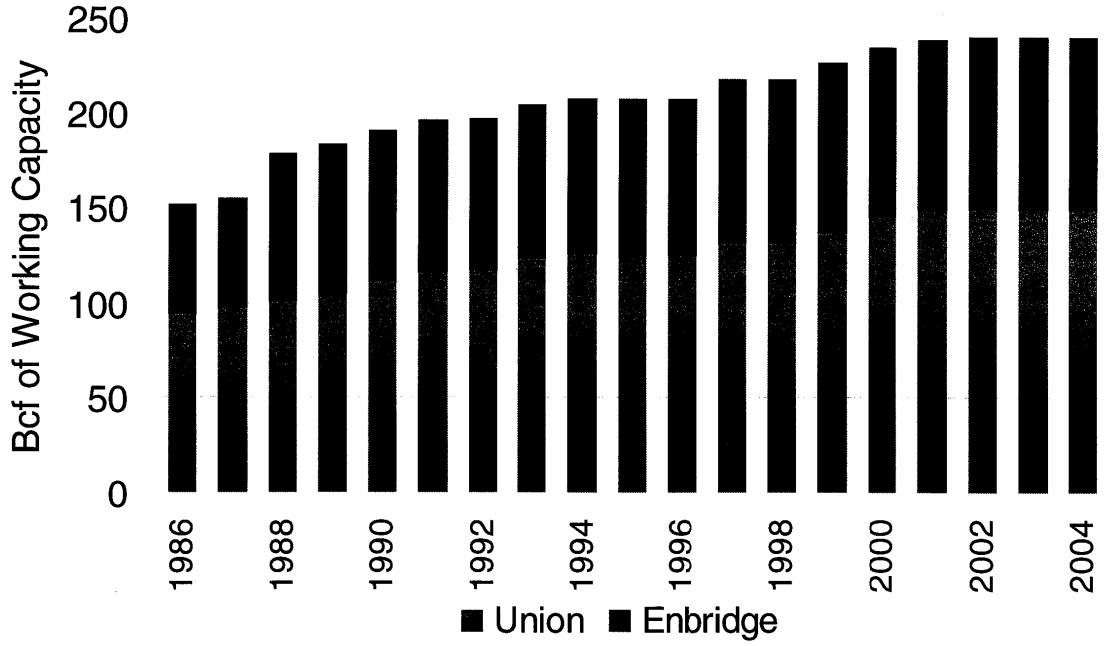
Pipeline Interconnections at Dawn

Dawn Storage Pools



Enbridge has 9 pools as well

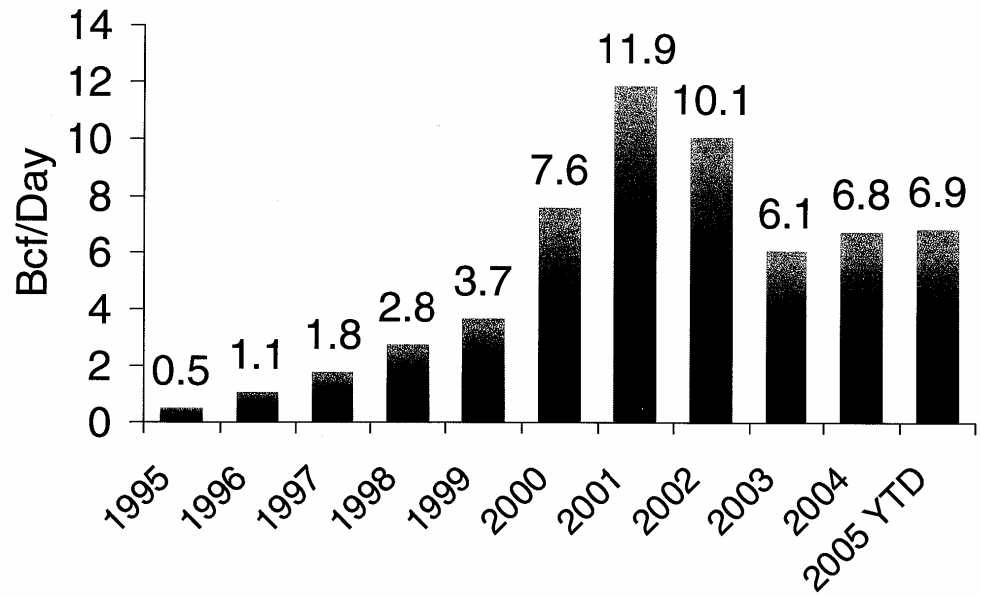
Union Gas & Enbridge Storage Capacity at Dawn



Additional storage capacity in Michigan +600 Bcf

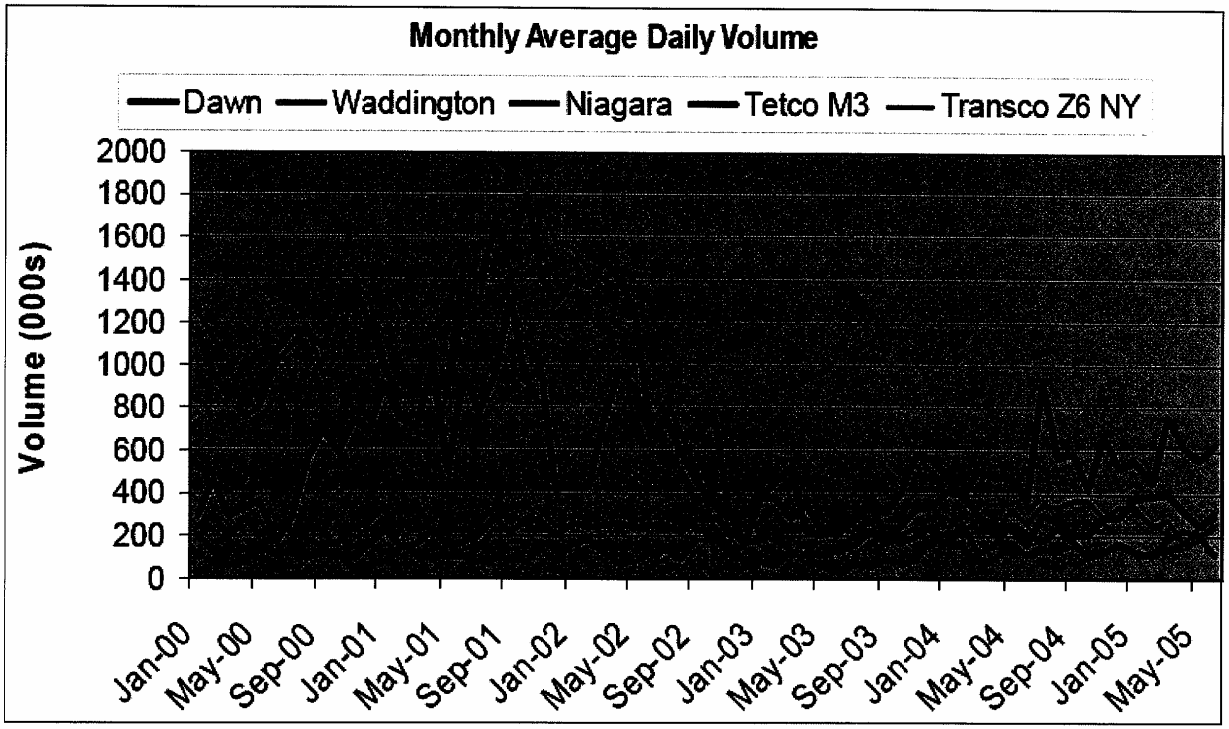
Dawn market activity

Average title transfer volume in Union Hub
(Bcf/day)



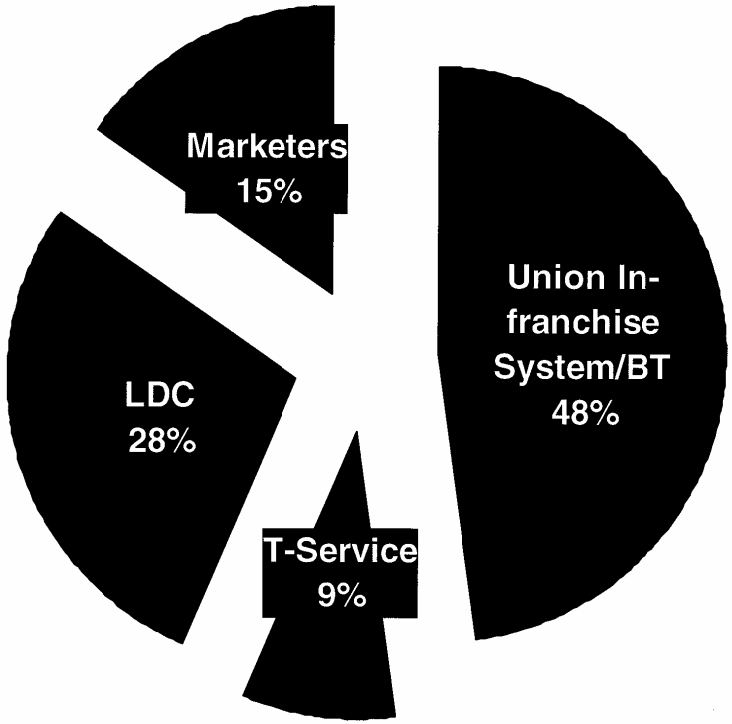
Dawn has over 6.9 Bcf/d of trading activity by over 100 parties

Trading at Dawn is increasing relative to other trading locations



Source: Gas Daily

Who contracts for Union storage?



Infranchise	**73 Bcf**
T-Service	**13 Bcf**
LDC	**43 Bcf**
Marketers	**23 Bcf**

Drivers for Dawn Growth

Drivers

1. **Trend to Short Haul – liquid market hub vs. supply hub**
2. **Abundant Storage – Ontario & Michigan**
3. **Connected to all Major Supply Basins**
4. **Reliable Pricing**
5. **Supply Header – Chicago to Montreal**
   - ❑ Feeds major export points at Niagara, Chippawa and Waddington
6. **NYPSC has approved Dawn as a liquid supply point**

Recent Activity

- ANE Shipper Group converting long haul TCPL to short haul to Dawn. Between 2006/2007 330,000 GJ/d incremental to Dawn
  - Equivalent to capacity required by 1650 MW of power load
- Vector expansion in 2007
- Millennium start-up in 2007. N.E. utilities sourcing incremental supplies at Dawn/N.Y. State. Incremental Dawn is 100,000 – 200,000 GJ/d (equivalent to 500 – 1000 MW of power load.

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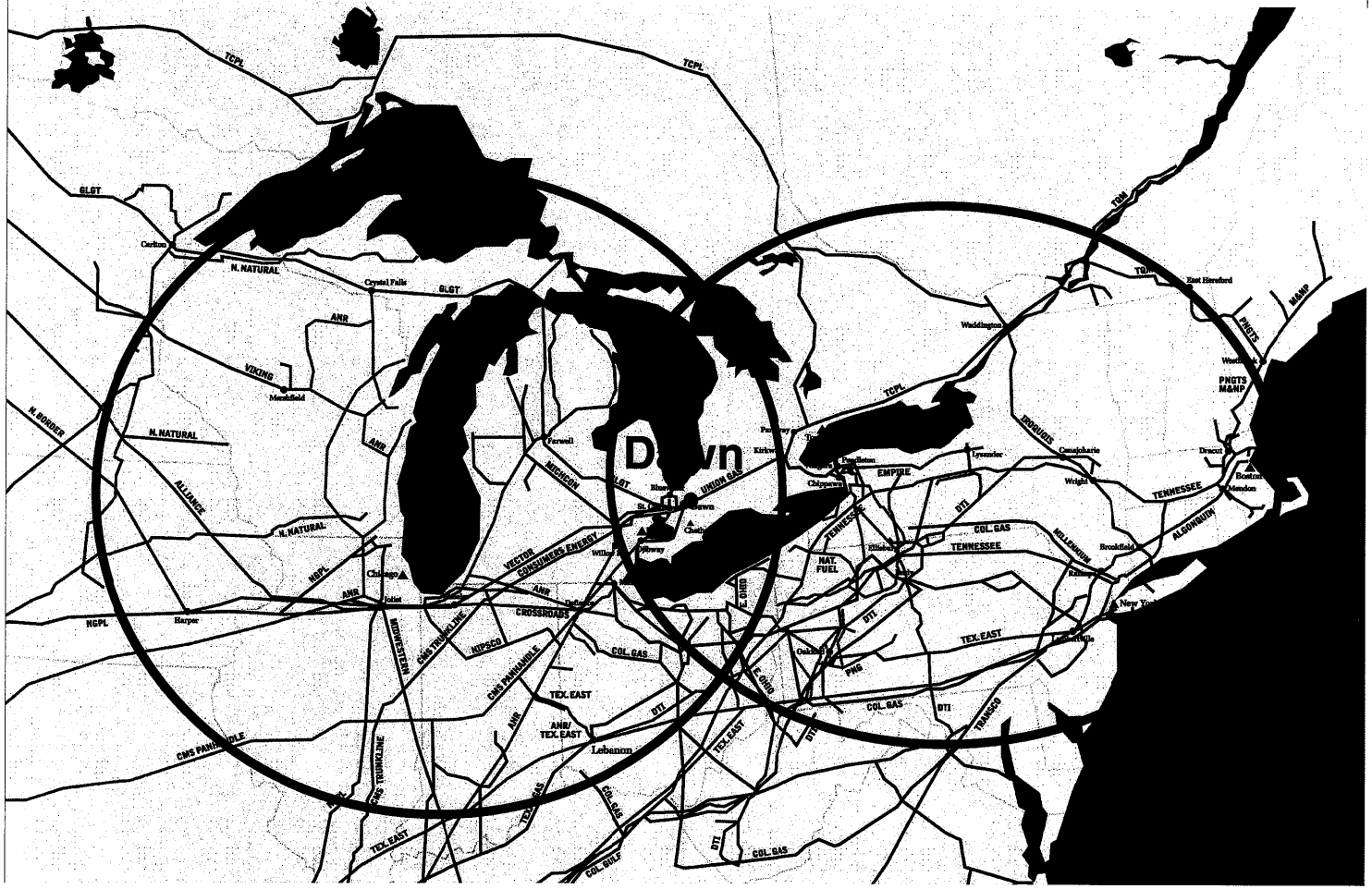
Reach of Dawn – Midwest to the Northeast



Dawn Growth

- Union's expansions in 2006 - 2008 may add in excess of 1.3 TJ/d of capacity (22% growth in Dawn to Parkway)
- Expansion of transmission capability typically leads to expansions of storage and deliverability
- Trend will be to expand interconnectivity between storage in Michigan and Ontario (Dawn)
- Expansions in 2006 – 2008 will bring new market participants to Dawn

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Union Gas Expansion

Open Seasons

Union Open Seasons

Union has held 3 recent open seasons

- Non-binding Open Season closed September 30, 2004
  - ❑ Storage and Transportation (all locations)
- 2006 Binding Open Season closed December 6, 2004
  - ❑ Dawn to Parkway or Kirkwall Transportation
  - ❑ In service date of November 1, 2006
- 2007 Binding Open Season closed February 18, 2005
  - ❑ Dawn to Parkway or Kirkwall Transportation
  - ❑ In service date of November 1, 2007

2006 Binding Transportation Open Season

Binding open season – closed December 16, 2004

Contracts executed with 22 parties

- Canadian LDC's – Enbridge, GMI, City of Kitchener
- US LDC's – ANE Shipper Group
- Canadian Pipelines - TCPL
- Marketers – BP, UBS, Energy Source
- Canadian End-users – TransAlta, Stelco

Total contracted quantity – 661,472 GJ/d

Average term – 11 years

2006 Binding Transportation Open Season

Process & Timelines:

- Reverse Open Season – November 2004
- Facilities Application – February 2005
- Duke Board of Directors Approval – May 2005
- Facilities Approval – June 2005
- Construction – Summer 2006
- In service – November 2006

Facilities Required:

- Brooke-Strathroy & Hamilton-Milton (38 km of 48 inch pipe)
- Dawn Compression and Parkway Re-aero (22,000 HP at Dawn)
- Approximate capital cost of $150 million

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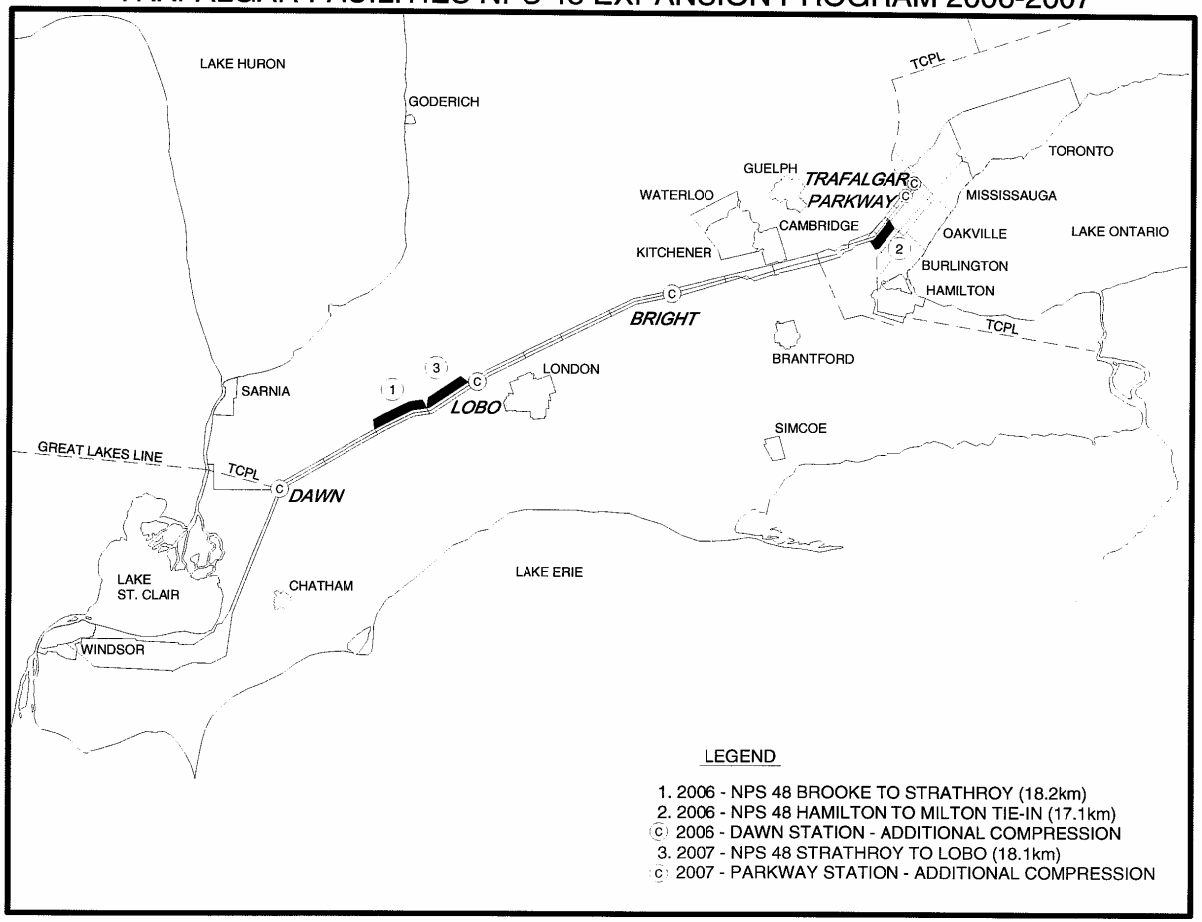
TRAFALGAR FACILITIES NPS 48 EXPANSION PROGRAM 2006-2007



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2007 Binding Transportation Open Season

Binding Open Season closed February 18, 2005

Total bids in excess of 1.0 TJ/d

Similar shipper groups participated:

- **Canadian LDC's**
- **US LDC's**
- **Pipelines**
- **Marketers**
- **Ontario Power Producers**
- **Canadian End-users**

Final quantities and contracts now being determined

Most of power load will shift to 2008/09

Expect to file OEB application in Fall 2005

2007 & 2008 Facilities Construction

Union is currently finalizing facility requirements for 2007 and continues to review facilities requirements for 2008

Drivers for 2007/08:

- **Ontario power**
- **Continued market growth**
- **Proposed expansions on Vector, Millennium and PNGTS**

Impacts of Ontario Power at Dawn

Impact on Dawn Parkway

- Rule of Thumb
  - 500 MW plant requires 100,000 GJ/d of pipeline capacity
- CES RFP has 650 MW of new gas-fired power generation in GTA
  - Required pipeline 140,000 GJ/d 2007/8/9
- Next RFP has 1500 MW of gas-fired power in GTA plus 1000 MW of cogen throughout province. If all cogen was in GTA, total GTA power gen is 2500 MW
  - Required pipeline 500,000 GJ/d 2008/9

Impact on Dawn Parkway

- Total potential power requirement of Dawn Parkway = 640,000 GJ/d
- Total capital required 2007 – 2009 would be $125 - $200 million if it all supply originated at Dawn
- Union's expected build in 2006 – 2008 = 1,300,000 GJ/d
- By 2008, if all planned expansion occurs, Union Dawn Parkway will be capable of 6,500,000 GJ/d
- Conclusion – Dawn Parkway expansion for power growth is feasible from capital and timing perspective

Impact on Storage at Dawn

- Rule of Thumb
  - ❑ 500 MW plant would require 500,000 GJ/d of storage space and between 6,000 – 50,000 GJ/d of withdrawal capability (1.2% - 10% deliverability)
- CES RFP of 1575 MW (Sarnia) and 650 MW (GTA) would require approximately 2,200,000 GJ of space
- Next round of power for GTA (including cogen) would require approximately 2,5000,000 GJ of space
- Union would provide storage space and deliverability to in-franchise power plants
- Union currently has storage assets in excess of in-franchise requirements that is marketed on a short-term basis at market based rates

Impact on Storage at Dawn

- As new in-franchise power plants come on stream, we would use existing storage assets to meet new demands
  - ❑ No new capital required for traditional 1.2% deliverability
  - ❑ Deliverability expansion may be required to meet higher withdrawal rates if requested by customers
- Power plants in GTA would most likely have load balancing provided by Enbridge
  - ❑ Union or others could also provide, if required, at market based rates

Impact on Upstream Supply

- Union contracted with EEA to model impact on upstream supply of Ontario proposed coal conversion to natural gas
- EEA
  - Based in Washington
  - Analysis behind National Fuel Council December 2003 Report
  - Completed margin study for AGA, INGA, etc.
  - Model includes over 120 market locations throughout North America
    - EEA runs a base case 6 times per year where natural gas supply/demand and price are solved for each market location. Dawn and Parkway are two of the market locations.
- Union asked EEA to run two sensitivities to the July base case
  - Case I – 2550 MW of new gas-fired power load 2007/08
  - Case II – 5050 MW of new gas-fired power load 2008/09

Impact on Upstream Supply

Major Conclusions:

- Majority of new volumes occur as incremental volume on Great Lakes and Vector (imports from Michigan). Minimal new volumes on TCPL's north line.
- Dawn basin impact minimal
- Rest of price impact is a North American impact
- Demonstrates how well tied in Dawn is to North America

North American Perspective

- Ontario is adding 5050 MW of gas-fired generation over 2007 – 2009
- The U.S. added 38,400 MW of new generation in 2003 (Source EIA)
- The U.S. plans to add 102,000 MW of gas-fired generation between 2004 – 2009 (Source EIA)

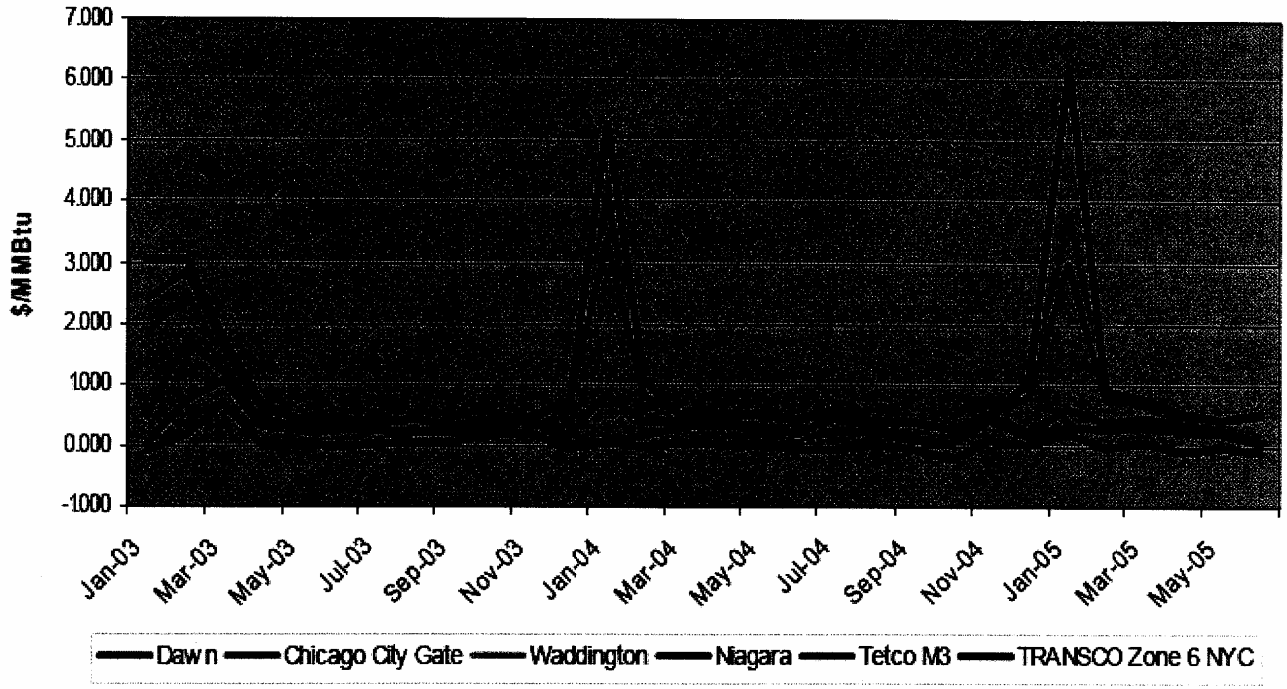
Impact of Dawn Daily Pricing

- CES contract has daily pricing set through NGX (day prior)
- Risk to power producers will be interday volume variances
- Solutions:
  - ❑ Commercial arrangement with Gas Marketers
  - ❑ Storage
  - ❑ IESO day ahead market

Other Options

1. North Bay Junction
2. East of Parkway
3. Parkway

Dawn Basis is less volatile compared to other trading locations



Source: Gas Daily

Conclusions

Conclusions

- Dawn is a strategic Market Hub, unique in North America – valuable to Ontario and Michigan
- Dawn represents assets and services of many stakeholders – not controlled by any one party
- Dawn attributes include:
  - ❑ Connected to every major supply basin in North America
  - ❑ Multiple pipelines tie into Dawn
  - ❑ Over 250 Bcf of Ontario storage and access to over 600 Bcf of Michigan storage
  - ❑ Over 100 parties trading at Dawn
  - ❑ Closest liquid hub – minimum infrastructure to market
- Required expansion on Union's Dawn Parkway transmission system is within normal capital planning
  - ❑ 2006 expansion will bring growth to Dawn in advance of Ontario power

I am asking the OPA to include a scenario with a minimum of 60% renewable electricity by 2020 and a full phase-out of dirty coal and unreliable nuclear power.

Thank you,

Saundi Vivian

Here are my recommendations for electricity for the future of Ontario: At least 60% of our energy should be renewable energy; all coal fired plants should be eliminated as soon as possible; unreliable nuclear energy should be phased out; and we should turn to hydrogen as the fuel of the future as described below:

THE PROBLEM: Fuel cells are ready to power our factories, retail, and office spaces. However, we don't have any cheap way to make hydrogen.

THE SOLUTION: Utilize our hydro and wind power sources of energy to make hydrogen at night when the demand for energy is low. Cheap hydrogen is a much better solution to our energy needs than building new nuclear power stations or repairing nuclear plants because hydrogen for fuel cells is cleaner and will be cheaper than nuclear power.

Please meet Ontario's energy needs thru conservation and renewable energy only. Please note that China is creating 1,000,000 kilowatts of new energy by 2020 from wind energy - so can we!

Also, there is innovative technology now to create hydrogen cheaply from wind energy which can power fuel cells for factories, offices, and shopping malls.

We either drastically cut pollution and CO2 gases - which is altering the world's climate - or we suffer droughts and famines, high rates of death from pollution, and severe weather such as smog, hurricanes and tornadoes.

Ontario needs to lead with clean energy and a clean environment.

Please reply. Thank you.

Sincerely,

Alan Warren

Subject: INNOVATIVE SOLUTION FOR CHEAP CLEAN ENERGY

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Please reply.

Sincerely,

Alan Warren

Here's the text of an article that I wrote for the Kingston Whig Standard when I was on the Community Editorial Board a few years ago. In a short, simple, non technical discussion it defines one Ontarian's views of the supply mix issue from the 30,000 foot level. As I mention in the article, quite frankly I don't have the in depth knowledge to go into more detail or technical justification. As background I was President of North bay Hydro until 2001 before moving to Kingston.

"Gone fission

GreenPower describes electricity produced by sources that are less harmful to the environment than fossil fuels. While there are no strict definitions of GreenPower, generally included are energy sources such as solar, wind power, geothermal, biomass, small hydroelectric and some count fuel cells.

It may sound crazy but nuclear power also fits the definition if, and that's a big if, we had a reliable, economic design and could solve the politics of waste disposal.

It's hard to advocate something when it's controversial, you're not an expert and most people will disagree with you but I'm a closet supporter of nuclear power. That is, nuclear power done right, with a safe, reliable design and acceptably safe waste disposal.

Why? Recently I read three articles: one said the price of natural gas is going up, up, up; the second said Ontario wants to commit to 3000 megawatts of wind power and the third said, "Told you 30 years ago nuclear power was a mistake".

Why do I mention this? Ontario needs new generation.

I am an ardent supporter of conventional GreenPower. The technologies all exist but the economics are uncompromising, which is why we aren't all rushing out and buying wind generators or installing photo voltaic cells. Instead we advocate that government go out and spend our tax dollars doing what we can't, or won't, do ourselves. While government is no stranger to wasting tax dollars, it is treading carefully in this area.

The other catch is that GreenPower like wind generators or solar panels work primarily as a supplement to conventional generation not as a complete substitute. GreenPower can't do it all. Demand for electricity is highest on the hottest days for air conditioning and the coldest days when we need heat. Unlike, say, coal generation, GreenPower could not be guaranteed to meet demand on those peak days.

There are other options.

The best is higher efficiency electrical equipment and conservation rather than new generation. Both are occurring gradually through evolutionary habit change and technology. Cash incentives would stimulate faster adaptation. An effective but negative incentive would be electricity pricing signals like those that spooked Ontarians so badly last year.

Our neighbours in Manitoba and Quebec have hydroelectric power that they will sell us. I like that. If we can rely on these resources they are worth pursuing.

Natural gas generation is cleaner than coal but gas prices are going ever higher. We can also use co-generation, which not only produces electricity but thermal energy for industrial processes or district heating. Another good idea, notwithstanding that it needs natural gas.

Nevertheless, I still like the idea of getting nuclear power right. Can't we salvage anything from the billions wasted and things done wrong? Somehow the notion of uranium heating water for steam to generate electricity that can heat and cool our homes; eliminate electricity generation

source greenhouse gases; recharge electric vehicles or even produce hydrogen as a fuel just seems to make sense in a vast country with a cold climate that needs energy to survive."

David Wills, P.Eng.

Dear Ontario Power Authority,

I am a 55 year old Toronto resident and writing to you not only on my behalf and that of my two daughters, but also on behalf of future generations. The time for short term thinking in relation to energy production is long past. There is much in the natural world, including the human body, that is telling us this, and has been for decades.

Canada and Ontario can be a model for sustainable energy practices. The world, particularly growing economies like China and India, and Third World governments need such models from the advanced economies.

Please seriously explore the possibility of generating 60% of Ontario's needs with renewable electricity by 2020 with a full phase-out of coal and nuclear power. There is much that says anything less would be a failure by our generation.

Thank you for giving this letter your consideration.

Sincerely,

Anthony R. Wilson

Submission on Power System Planning

The blackout of August 2003 underlines the simple fact that electricity underpins every aspect of our society and economy. Our modern way of life can be pushed back in time by 100 years in an instant without electricity. It is the basis of Ontario's prosperity which directly affects the prosperity of the country. Electricity is not a commodity, it is an essential service.

Most importantly, an energy policy must be rooted in principles of sustainable energy development. The supply mix is then evaluated and selected to meet the goals of that policy. This is what planning the future must consider – that our energy policy is also fundamentally an environmental policy.

How we use energy has a profound effect on the load we all place on the environment. Energy options for the future cannot be decided by partisan political interests or private interests promoted by lobbyists. It also cannot be done without a commitment to a long term vision for a sustainable energy system and strategic planning formulated to achieve it. Transparency of a strategic energy plan would be guaranteed by comprehensive review of the economic, social and environmental risks and benefits and full public discussion therein. To date this has not happened since the public review of the last demand supply plan in 1990 was prematurely terminated by the sitting government.

We currently have no long term plan to ensure balanced, timely, safe and sustainable energy supply. Ontario requires an affordable and competitively priced energy guaranteed under a managed public system of supply to ensure the benefits accrue directly to the people of Ontario.

Current policy is rooted in using private interests motivated by private profit to build only according to market signals. Signals that most economists agree are fundamentally driven by greed and fear. This is not a reasonable base on which to rest the security of Ontario's most fundamental service. Ontario must be energy self-sufficient this is the first principle for evaluating the supply mix.

An Electricity supply system needs to consider planning horizons of no less than 50 years. Increments of 5 year plans to 2015 and 10 years from there onward. 50 years provides some idea of how far out of whack we will go if demand and supply are not sustainable or realistic. Full life cycle assessment must be undertaken for all fuel cycles within a full strategic environmental assessment rooted in an integrated resource planning framework.

Demand side management, conservation and renewables must be considered and the scale of their contribution clearly elaborated. Use of renewables when the average household uses more than 13MWh/yr of energy is out of scale with their capability to reasonably supply energy. Lobbyists have led the public, the media and politicians to believe that we can shut down coal and nuclear plants and live on windmills. This is a clear failure in informed decision making.

Conservation should be factored into the mix and consider factor 4 and factor 10 reductions through efficiency, new technology, incentives – disincentives and most importantly, education. The OPA must undertake to educate a public that does not understand the strategic importance and essential nature of the power supply planning. It must also educate the government so that politicians can no longer use political interests to interfere in a process that requires science and the rigour of risk assessment to make balance decisions about the future.

Lastly, if the OPA wants to invite thoughtful written submissions from interested parties ie. the public, it needs to provide ample time and information to the public of its intention to do so. This call for written submissions is not even clearly found on your website. The tactic of making this call in the depths of summer with virtually no public notice is the same tactic the government used when asking for feedback on Bill 100. It appears as a deliberate tactic to stay under the public radar and limit response.

I would very much like to know what steps were taken to provide public notice of this call. The public looks to the OPA for leadership to help plan our way out of this electricity policy mess we are in. This is not inspiring my confidence. I would have been more articulate but I only found out today about this call for written submissions.

L.J. Wood
Mississauga, Ontario

I am writing to urge the OPA to develop an energy plan that features a minimum of 60% renewable electricity by 2020 and a full phase-out of dirty coal and unreliable nuclear power. The oppressive heat and energy use of this summer have only highlighted the need for Ontario to work smarter and think outside the box when it comes to energy sourcing.

Deborah Woods

I would like to add my voice to those supporting a plan for Ontario to generate 60% of its electricity needs through renewable energy.

The Pembina Institute and the Ontario Clean Air Alliance have published some great research showing how possible this is. See www.cleanairalliance.org/resource/15month.pdf.

We it to owe our children to make more responsible energy decisions. I am very happy about this government's plan to phase out coal-fired plants, and the next thing we should aim to eliminate is natural gas, then nuclear power. Just imagine: our children's' air might be cleaner, there might be less spent uranium to dispose of or worry about leaching into a water table.

Do the right thing. Go renewable.

Sincerely,

Marc Xuereb

Aug.24, 2005

Ontario Power Authority,

Dear Sirs,

I am the founder and head of The Orangeville and Dufferin Wind Co-op, also called Orange Wind. We have no turbines erected at present but aspire to build 10 to 20 megawatts worth in our first stage of building. The Orangeville Town Council is supportive and so are most people I run into. In our funding model we would work as a traditional co-op and sell directly to members and provide a discount to current costs. Our members would include not only residents and industry but also the town and the local school boards – all at a 10% discount.

First let me say that I am both amazed at your patience and thoroughness in dealing with all of the many people and groups that wish to engage in the de-regulatory and re-regulatory process. One would naturally expect conflicting submissions, each with a bias favouring the source. However, I am surprised by many interventions that I consider blatantly self-serving and some which seem to have the objective of micro managing the process as if they were the OPA itself. Cynically I also believe some wish simply to delay the process for as long as possible for their own ends.

Regarding the <u>future mix of electric power sources</u> in Ontario and the <u>role of distributed generation, specifically small local and community owned generation</u>, I believe I have some concerns and observations that may help you in the decision making process.

<u>Summary</u> Antiquated regulations that make locally owned distributed power less economic will also likely hinder the Province obtaining the desired proportions of renewable electrical generation it wants, and which most of the voters of Ontario want.

Concern 1) Old laws and regulations that no longer serve their original intent.

a) Laws and regulations are implemented to further some aspect of government policy. They have the effect of changing the market place equilibrium, to the favour of some and the disadvantage of others. Some of these changes are unintended.

b) When the laws or regulations no longer further the original government policy, they should be dropped so that the market returns to a normal equilibrium.

c) They should not be maintained because some who were unintentionally favoured like their favoured status.

Concern 2) Specifically the rule obliging LDC's to collect transmission fees even when the power concerned did not pass through any transmission lines.

a) This regulation will likely make my co-op uneconomical until power prices are higher. As you know wind power is only marginally economic. Thus the current rule that penalizes local distributed generation in general, in Dufferin County specifically penalizes also the 50,000 local residents, plus local industry, plus local government and the school boards. In our model after we pay for local distribution, the penalty is about 10% of our potential cash flow. That is a lot of penalty, when there appears to be no economic or policy rational.

b) Surely the money should go to the transmission company or the fee dropped.

c) If you collect fees against local power that did not use the transmission lines, perhaps you should also collect fees against conservation efforts that reduce the use of transmission lines.

Concern 3 Our finance model would not benefit from SOC's, (Standard Offer Contracts) but should these come into being, they will have to be that much richer to offset the existing penalty.

Concern 4) Biodigesters that generate power with the waste gases are well established in Europe and are relatively cheap to build because they are at a point where there is an off the shelf design available for every need.

a) In contrast, in Canada, omitting wood waste biodigesters there are fewer existing ones than fingers on two hands. There is a wide range of possible feed stock combinations. Each plant is built specifically for a specific feed stock combination. This means that in Canada at present each plant is completely designed from scratch. This is expensive. This is an important technology with many direct and indirect benefits that should be encouraged rather than penalized. Financial penalties will only cause delay, more costly alternate solutions and perhaps even health problems.

b) For example, Orangeville has a water treatment plant that is reaching its capacity limits. Orangeville while surrounded by farmland must send its sewage sludge to other counties for disposal onto farmland. There is fear that finding such land is going to be progressively more difficult. With a biodigester plant added, the current plant limits are manageable for a while longer, and there would be 75% less sludge to get rid of.

c) Also, about 25,000 residents in the rural areas of Dufferin County use septic tanks. The local septic tank cleaning company is nearly at the final limits on the property

where its sludge is dumped. It is not likely to find another site in this county. This means greatly increased costs for this necessary service.

d) It would be not only easy to put the septic waste into the Orangeville biodigester but it would apparently improve the process. The power generated from the waste gases would help make the costs more manageable. The plans are however on hold for the indefinite future.

e) Toronto is having progressively more trouble getting rid of its sewage sludge. Biodigestors would probably help them a great deal also.

Concern 5. That Ontario is going the way of Great Britain rather than Denmark.
In Britain the tax laws favour large utilities or specialized wind companies. There was a short period of support, but I believe for about the last ten years about 80% of all wind farm proposals have been turned down at the local council level. There is a lack of strong support, but there is a very vocal negative minority who are most active.

Contrast this with Denmark where the tax laws favour local ownership. Many people also do not like the turbines but almost everyone benefits or knows someone who does. The local town or village may own the turbine and local people get cheaper power. Alternately they may know the turbine is directly owned by one or more local farmers.

Dufferin County is very lucky to be away from the Great Lakes and yet have a viable wind regime. As I write the Wind Farm owned by Canadian Hydro Developers of Calgary is under construction. It is the first in this county or any adjacent township. The local landowner obtains a fee for his land use. There is no fee paid to immediate neighbours who may actually live closer to the turbine than the landowner hosting the turbine. Some do not mind. Many feel they will suffer an ascetic burden without a benefit. Local taxes are minimal.

Already I am hearing discord about wind turbines in my own circle of acquaintances, most of whom are enlightened and very “green”. “We suffer all this mess just to send power to Toronto!” “What’s in it for us?” As someone who grew up in Toronto I never realized until recently that many rural people bear real emotional antagonism toward the cities.

A local co-op that could provide cheaper power from wind turbines to locals is an easy means to reduce the feelings that most locals are getting nothing from the wind farms.

Otherwise I would predict that some of Canadian Hydro Developers’ plans to build an additional three extensions to their wind farm are going to get turned down by the council. That would also go for several other proposed wind farms that are not yet approved.

The policy of encouraging large wind farms owned by outsiders and penalizing small locally owned ones is going to backfire badly on the province as local residents start to understand the apparent double standards. Not just here, but right across the province. This will at the very least slow down the deployment of wind power, which seems to be a cornerstone of the government's plans to shift away from coal.

Concern 6. There seems to be an assumption that all wind power must feed into the transmission system.

Concern 7. There seems to be a total discounting of the possibility that co-op's or other local or initially small enterprises have the potential for significant electrical production over time. I should point out that several major Canadian Life Insurance companies are co-op's as are Credit Unions.

Summary Antiquated regulations that make locally owned distributed power less economic will also likely hinder the Province obtaining the desired proportions of renewable electrical generation it wants, and which most of the voters of Ontario want.

Yours Sincerely,

Robert Younker, P.Eng. CFA.